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A LABORATORY MODEL STUDY OF WATERFLOOD BEHAVIOR IN LINEAR SYSTEMS

A THESIS
SUBMITTED TO THE FACULTY OF GRADUATE STUDIES
IN PARTIAL FULFILLMENT OF THE REQUIREMENTS FOR THE
DEGREE OF MASTER OF SCIENCE IN PETROLEUM ENGINEERING

DEPARTMENT OF CHEMICAL AND PETROLEUM ENGINEERING

by

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ABSTRACT

There is conflicting evidence in the literature as to the effect of water injection rates on oil recovery. A laboratory study was made to gain a better understanding of the factors which influence waterflood behavior in linear systems.

Results have indicated that under a wide range of conditions where stabilization has not been attained, the oil recovery obtained by water frontal displacement tests is rate sensitive. The problem has been approached by considering the unsteady state equations describing linear flow through porous medium to arrive at factors which determine the behavior of linear waterfloods. Variables and parameters have been grouped to form "scaling coefficients" for correlation purposes.

The results obtained and explanations of the observed phenomena are presented and discussed.

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INTRODUCTION

There is ample evidence in the literature as to the effect of water injection rates on oil recovery, both in water-wet and oil-wet systems. Various investigations(5,11, 12,13,17,20,24,26) have shown that with increased water injection rates, the oil recovery would be increased, decreased, or rate independent. Although these studies have clarified certain aspects of linear waterflood behavior, there still exists some contradictory or misunderstood concepts which affect the applicability of laboratory model flow tests for field performance prediction.

The analysis of the displacement of oil by water was made possible by the theory and associated equations established by Buckley-Leverett(3) and later extended by Rapoport and Leas(24). On the basis of developed theory it is realized that flooding behavior is dependent upon the length of the system, the rate of injection, the core properties, and the fluid viscosities. Moreover, this theory suggests that linear waterfloods, if carefully conducted, should exhibit scaling and stabilization properties. An experimental investigation verifying these properties in an oil-wet system was performed by Rapoport and Leas(24). However, in water-wet systems, experimental results appear inconsistent. This may be attributed to the fact that the

scaling and stabilization properties have not been satisfactorily attained in many cases.

With these fundamental objectives in mind, a laboratory study was made to gain a better understanding of the factors which influence oil recovery by waterflooding. Waterflood tests were performed on a limestone core, on an unconsolidated sand pack, and on two alundum cores. The cores were initially water-wet. An attempt was made to reverse the wettability of a system to determine if displacement efficiency could be improved. Distilled water was used as the displacing phase and various viscosity oils were used as the displaced phase. The experimental data obtained was correlated on the basis of a scaling coefficient(24) which adequately describes the nature of linear waterfloods.

THEORY

A theoretical analysis of the displacement of oil by water was originally established by Buckley-Leverett(3). Their equations have been assumed adequate for the general solutions of oil recovery by waterflooding. If, for simplicity, the gravitational effects are neglected and/or a horizontal system is considered, then the fractional flow formula is as follows:

$$f_w = \frac{1 - \dfrac{K_o}{\mu_o \, q_t} \left(\dfrac{dP_c}{dx} \right)}{1 + \dfrac{k_o}{k_w} \dfrac{\mu_w}{\mu_o}} \qquad \ldots\ldots\ldots \ (1)$$

where: f_w = fraction of water flowing at any point

K_o = effective permeability to oil (darcies)

k_o, k_w = relative permeability to oil and to water respectively (md)

μ_o, μ_w = viscosity to oil and to water respectively (cp)

q_t = total flow rate (cc/sec)

P_c = capillary pressure (atm)

x = length (cm)

Many investigators made simplifications to equation 1 which were not originally intended, such as arbitrarily dropping the capillary pressure term. This suggests

that flow behavior is governed only by the relative permeability and viscosity ratios. They attempted to justify their disregard of the capillary pressure term by stating that as the flow rate is increased the term becomes negligible. However, as the rate is increased the term does not become arbitrarily small because the saturation gradient at the flood front approaches infinity. Thus the ratio of the saturation gradient to the rate is indeterminate. The capillary pressure term can be dropped only if the saturation gradient approaches zero as it does for high water saturations for long enough systems.

Rapoport and Leas(24) extended the Buckley-Leverett theory and presented a more detailed formulation of the nature of waterflood behavior. They utilized the unsteady state flow equations and obtained a mathematical description of the transient flow phenomena through a porous medium for linear horizontal systems. They assumed that only oil and water were present and acting as a totally incompressible and immiscible system. Gravity was also neglected. Their approach was to consider infinitesimal volume elements.

The equations applicable are:

$$V_o = -K \left(\frac{K_{ro}}{\mu_o} \frac{\partial P_o}{\partial x}\right) \qquad \ldots\ldots\ldots \quad (2)$$

$$V_w = -K \left(\frac{K_{rw}}{\mu_w} \frac{\partial P_w}{\partial x}\right) \qquad \ldots\ldots\ (3)$$

$$P_w = P_o + P_c \qquad \ldots\ldots\ (4)$$

$$\frac{\partial P_w}{\partial x} = \frac{\partial P_o}{\partial x} + \frac{\partial P_c}{\partial x} \qquad \ldots\ldots\ (5)$$

$$\phi \frac{\partial S_w}{\partial t} = \frac{\partial V_o}{\partial x} \quad \text{for oil} \qquad \ldots\ldots\ (6)$$

$$\phi \frac{\partial S_w}{\partial t} + \frac{\partial V_w}{\partial x} = 0 \text{ for water} \qquad \ldots\ldots\ (7)$$

where: V_o, V_w - flow rate per unit cross sectional area for oil and water respectively (cm/sec)

K_{ro}, K_{rw} - relative permeability to oil and to water respectively, dimensionless function of saturation (fraction)

K - absolute permeability (darcies)

P_o, P_w - pressure in oil phase and water phase respectively (atm)

ϕ - porosity (fraction)

S_w - water saturation (fraction)

t - time (sec)

x - length (cm)

Equations 2, 3, 5, 6, and 7 represents five simultaneous equations defining the dependent variables V_o, P_o, P_w and S in terms of space and time coordinates x and t.

The flow rate and pressure functions were eliminated by applying boundary conditions and putting the expressions in dimensionless form. The following equations are derived:

$$\frac{\partial S_w}{\partial T} + \frac{dF}{dS_w}\frac{\partial S_w}{\partial X} - \frac{K}{M}\frac{1}{LV\mu_w}\frac{\partial}{\partial X}\left[K_{ro}\ F\ \frac{dP_c}{dS_w}\frac{\partial S_w}{\partial X}\right] = 0 \quad \ldots (8)$$

$$K_{ro}\left[1 + \frac{K}{LV\mu_w}K_{rw}\frac{dP_c}{dS_w}\frac{\partial S_w}{\partial X}\right] = 0 \text{ at } X = 0 \text{ for any } T \quad \ldots (9)$$

where: M - oil-water viscosity ratio

L - length of flooded system (cm)

V - total flow rate per unit cross sectional area (cm/sec)

T - $\frac{tV}{\phi L}$ dimensionless time coordinate

X - x/L dimensionless space coordinate

F - $\left(1 + \frac{k_o}{Mk_w}\right)^{-1}$ function of relative permeabilities and viscosity ratio.

- All other terms as defined previously.

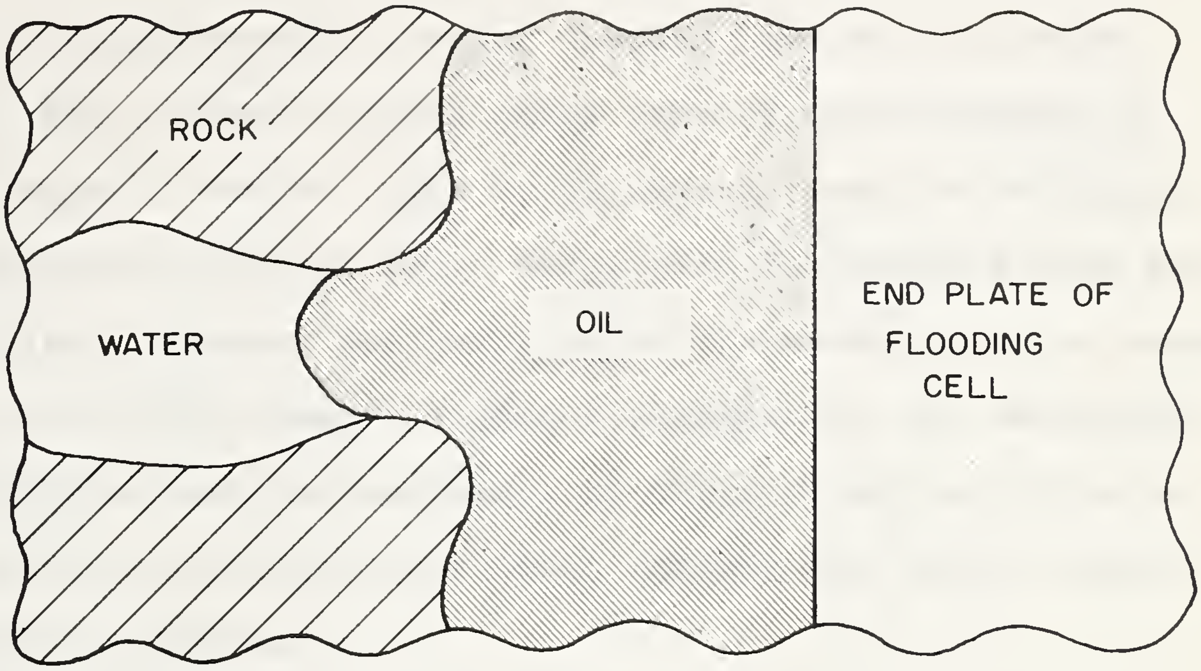
However, equations 8 and 9 are not subject to formal solution. Nevertheless, they indicate that the linear flood behavior is determined not only by the nature of the porous medium and the fluid system (i.e., specific values of porosity, permeability, viscosities, and definite relative permeability and capillary pressure functions), but also by the length of the flooded system and the injection rate. A

grouping of variables ($LV\mu_w$) in equations 8 and 9 has been defined as a "scaling coefficient." A more generalized form(11) involving the water-oil interfacial tension and the contact angle has been suggested. However, because of the experimental difficulties involved in imposing precise variation on either the interfacial tension or contact angle, consideration has been given to only $LV\mu_w$. This scaling coefficient has been assumed to adequately describe the nature of linear waterfloods and is conveniently used as a basis for correlation purposes. It can be shown that for a given porous medium and a given water-oil viscosity ratio, all floods corresponding to the same scaling coefficient must behave similarly and yield equal recoveries for the same cumulative injection. It should be stressed that preliminary knowledge of such data as capillary pressure, wettability, interfacial tension, viscosities and relative permeabilities is essential in the interpretation of the water flood behavior.

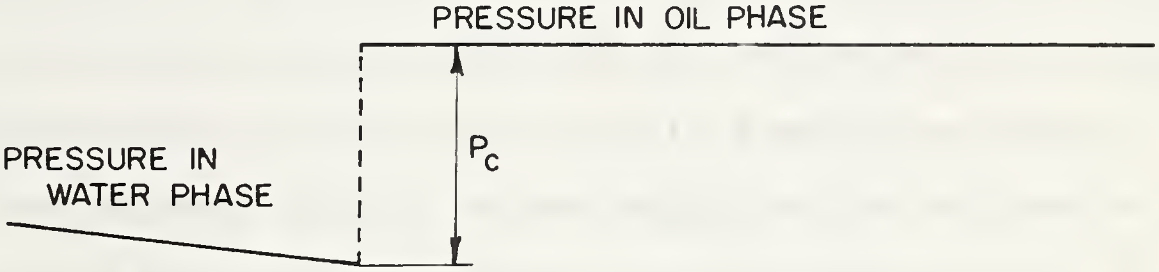
Capillary pressure is defined as the difference in pressure between a continuous oil phase and a continuous water phase in a porous medium. The displacement of oil by water involves capillary forces in two ways(21, 26). They exert a controlling influence on the microscopic fluid distribution which in turn is reflected upon the macroscopic flow

behavior. In the first case, the magnitude of these forces is governed by the wettability, the geometry of the pore spaces, and the interfacial tension. In the latter case, differences in saturation at the flood front results in capillary pressure gradients. This causes water to flow preferentially ahead of the flood front. Thus at low flow rates in short cores, the capillary pressure gradients may control the flooding behavior. However, these capillary pressure gradients are negligible in long homogeneous sands, at high rates in laboratory work, or at any rates in laboratory work as the residual oil saturation is approached. Thus, waterflood experiments should be compared at or near the residual oil saturation (i.e., at high WOR).

The so-called capillary end effect at the efflux face of a core in a water-wet system(17) occurs because of the discontinuity in capillary pressure across the boundary when the flowing fluids leave the porous medium. This results in an excessive water saturation at the outlet face and a delay in the water breakthrough time as compared to the time of water arrival at the effluent end. Water will not leave the core when it first reaches the outlet face but will accumulate inside and only oil will be produced. Figure 1 shows schematically the conditions existing in a water-wet system when water first reaches the outlet face.



a. Water Invaded Pore at the Outlet Face.



b. Pressure Distribution.

FIG. 1. CONDITIONS EXISTING IN A WATER-WET SYSTEM WHEN WATER FIRST REACHES THE OUTLET FACE.

(FROM REFERENCE 17.)

Figure 1a illustrates a water invaded pore at the outlet face. The pressure on the water side of the interface is lower than on the oil side by an amount equal to the capillary pressure (Figure 1b). Water will be produced only when sufficient pressure has built up in the water phase to exceed that of the oil phase. Figure 2 illustrates the saturation distribution and the influence of water injection rates on this distribution as water first reaches the outlet face in a water-wet system.

The saturation distribution after water arrives at the outlet face in a water-wet system is illustrated in Figure 3. Figure 4 demonstrates the corresponding saturation distribution in an oil-wet system. It is apparent that the water saturation is much lower at the outlet face in an oil-wet system than at the outlet face in a water-wet system. Thus, the adverse results of the capillary end effects at the outlet face are less pronounced in an oil-wet system. It can be expected that an increase in oil saturation towards the producing end, after oil is no longer produced, will occur in an oil-wet system. This end effect is decreased by an increase in pressure gradient.

Conditions existing in a water-wet system when water production starts are shown schematically in Figure 5.

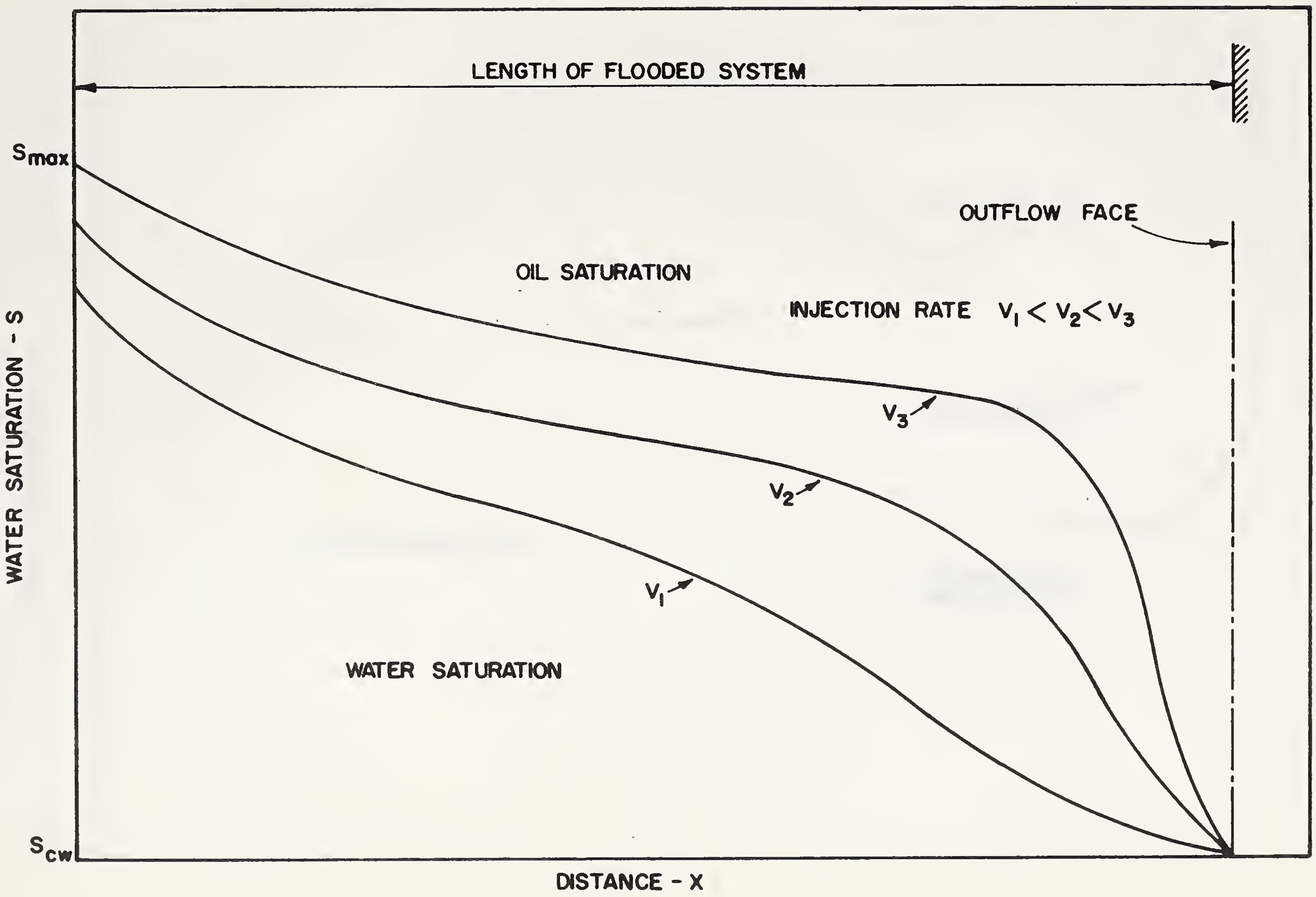


FIG. 2. INFLUENCE OF INJECTION RATES ON THE SATURATION DISTRIBUTION AS WATER REACHES THE OUTLET FACE IN A WATER-WET SYSTEM.

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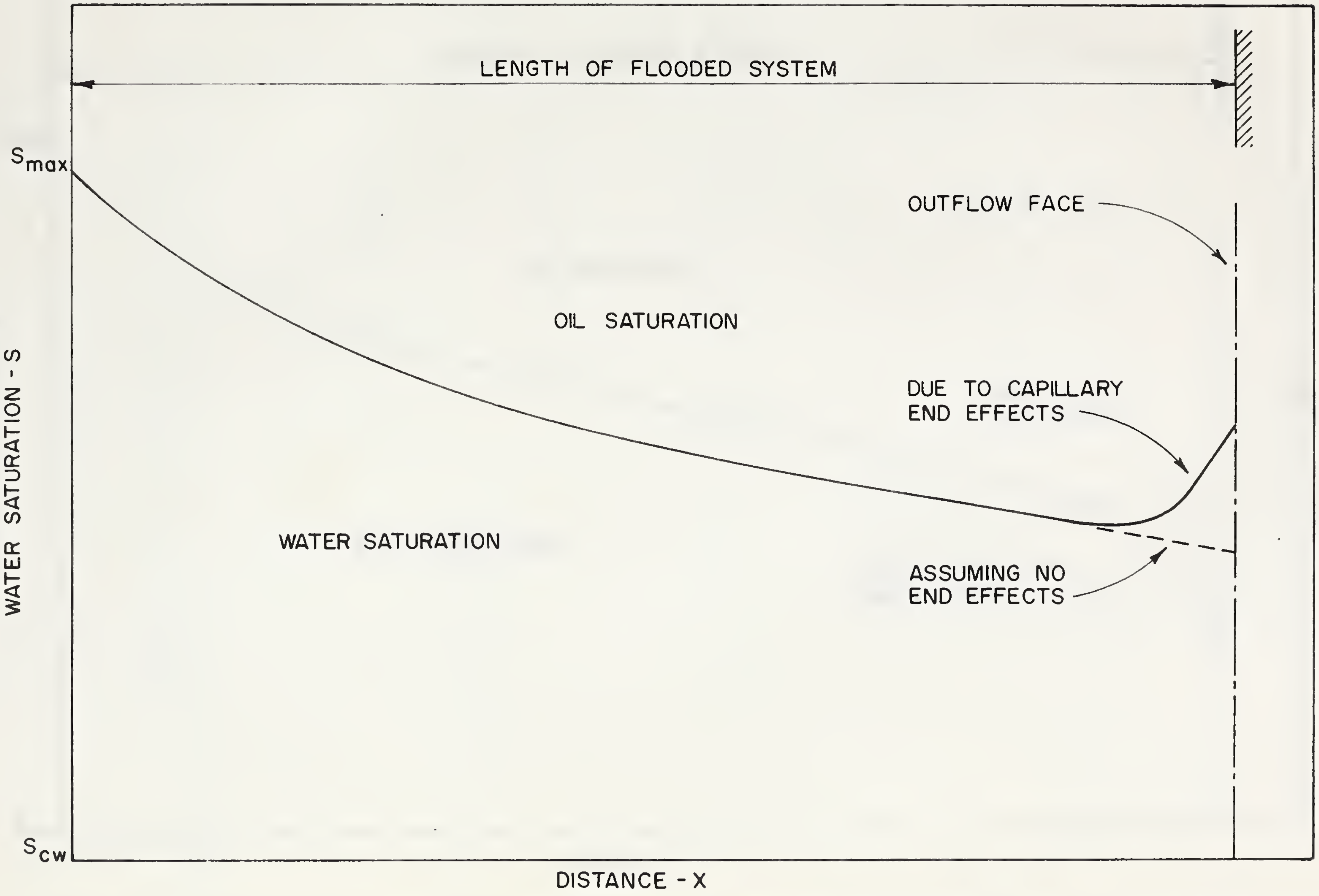


FIG. 3. SATURATION DISTRIBUTION AFTER WATER ARRIVES AT THE OUTLET FACE IN A WATER-WET SYSTEM.

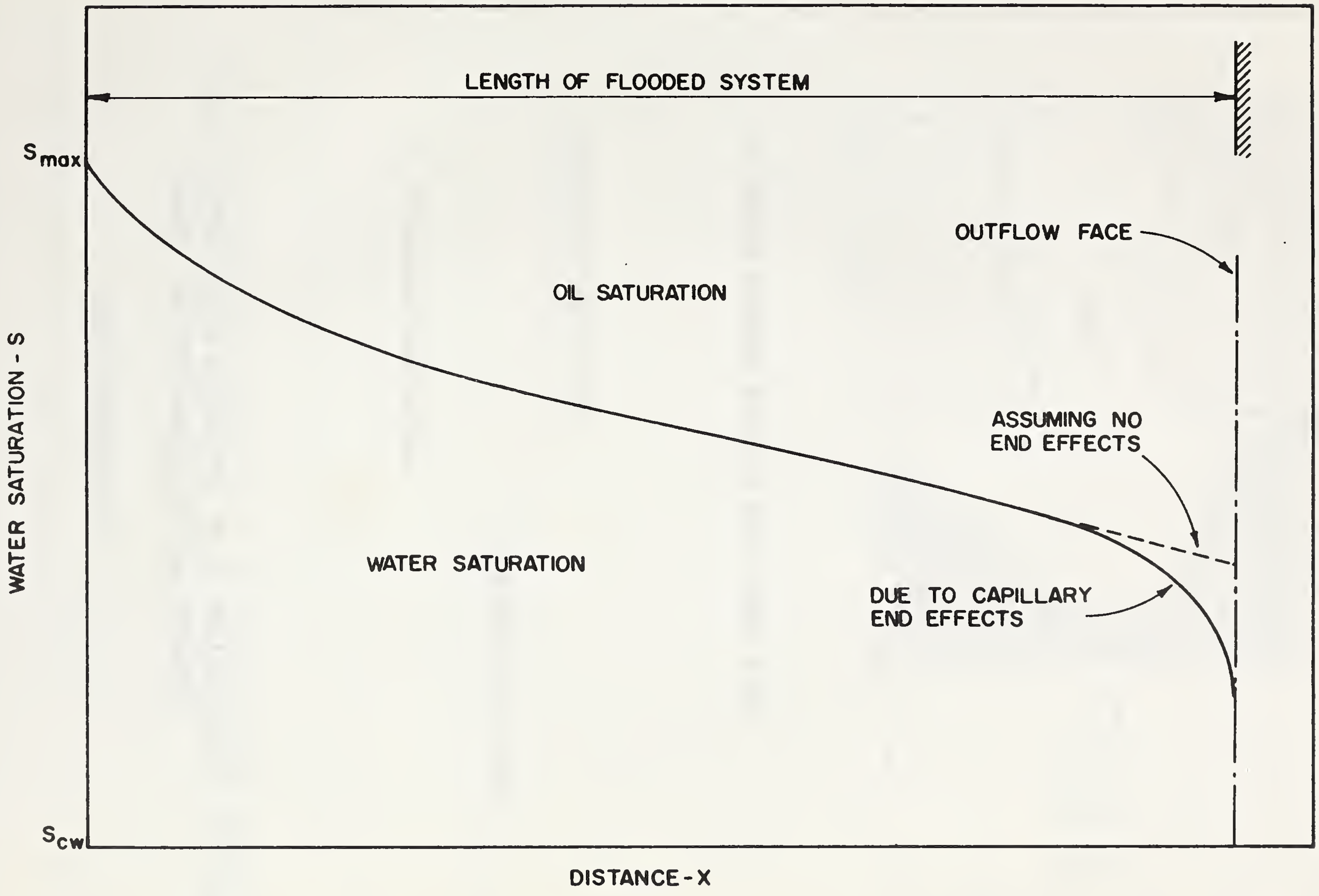
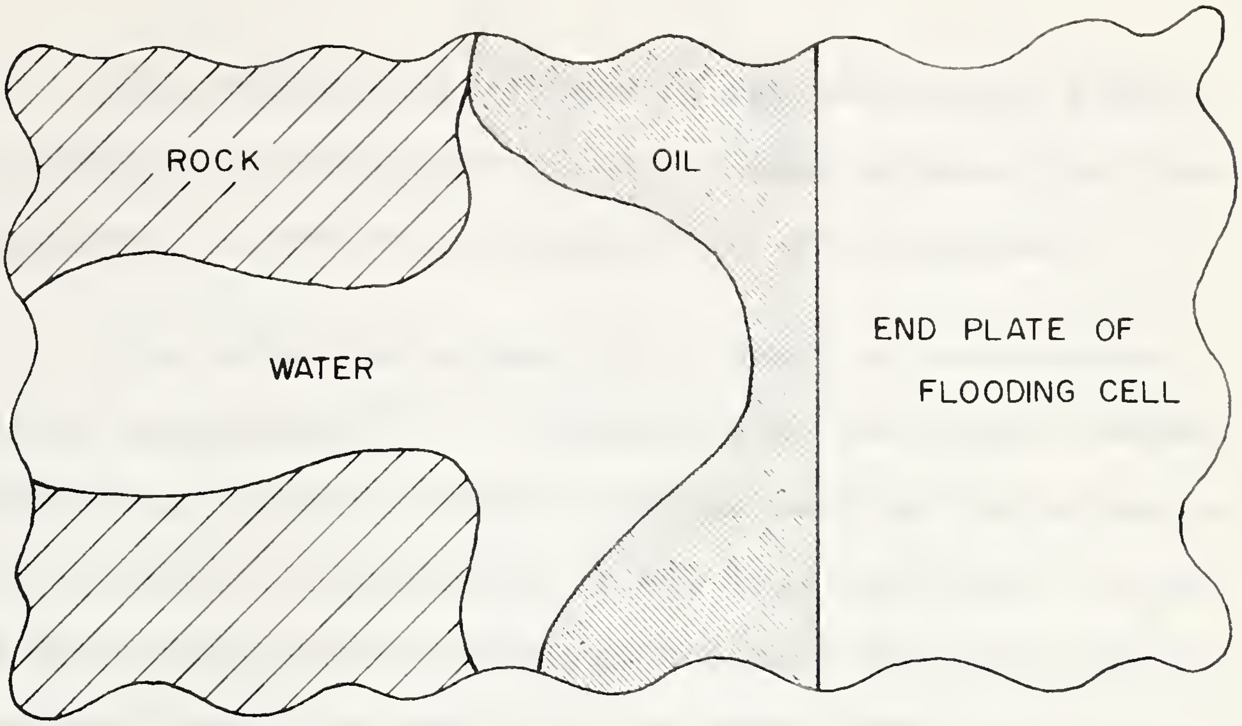
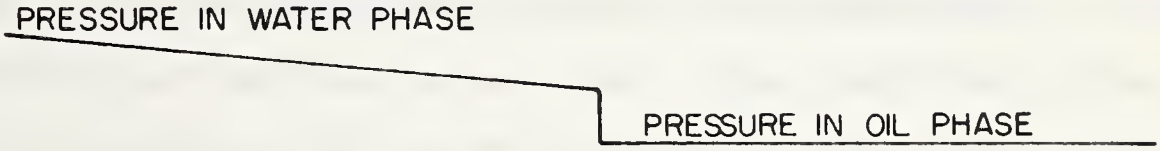


FIG. 4. SATURATION DISTRIBUTION AFTER WATER ARRIVES AT THE OUTLET FACE IN AN OIL-WET SYSTEM.



a. Water Invaded Pore at the Outlet Face.



b. Pressure Distribution.

FIG. 5. CONDITIONS EXISTING IN A WATER-WET SYSTEM WHEN WATER PRODUCTION STARTS.

(FROM REFERENCE 17.)

The relative importance of the outlet end effect will decrease as the length of the flooded system, the rate of injection, or the fluid viscosities are increased.

The inlet end effect is a result of spontaneous localized imbibition(17). Immediately as the water reaches the inlet face it will imbibe into the core at the points of contact causing a counterflow of oil from the core. As the flood progresses, water continues to enter the core only in a localized area (i.e., the injected water covers only a small portion of the core face near the injection port). This aids to the establishment of a region of non-linear flow. However, capillary forces within the core tend to distribute the injected water over the cross-sectional area. At low injection rates these forces are significant and they prevent deviation from linear flow. This inlet end effect is more pronounced for short systems, for high water injection rates, and for high oil-water viscosity ratios.

If water tends to displace oil from a rock surface, the rock is termed preferentially water-wet. Similarly, if oil tends to displace the water, the rock is termed preferentially oil-wet. The importance of rock wettability has been investigated by several authors(1,16,19). Their studies revealed that more oil is recovered from water-wet systems in the early flooding stages (i.e. recovery to water break-

through) than from oil-wet systems. When the rock is preferentially oil-wet the displacing water will invade the more conductive portions first, resulting in lower displacement efficiencies(7).

Other studies(14,18) suggest that oil recovery by waterflooding from cores of intermediate wettability may be greater than the oil recovery from either strongly water-wet or strongly oil-wet cores. Thus, the concept of wettability adjustment to improve oil displacement efficiency is realized. The degree of wettability is essential in order to perform accurate reservoir calculations and to predict waterflood performance. Moreover, wettability in the displacement of oil by water is important in that it determines the manner in which interfacial tension and flood rate affect oil recovery.

The results of waterfloods performed in the laboratories are often inconsistent. It is suggested that these inconsistencies can often be traced to changes in wettability of the porous medium before or during a test.

Recent investigations(9,25) indicate no change in relative permeability to oil and to water by a change in the injection rate. They suggest that the reported sensitivity of relative permeability to rate was probably due to the

effects of fluid saturation hysteresis or of changes in wettability.

Heterogeneity of the porous medium to be flooded can lead to considerable difficulty in the maintenance of a uniform flood front. As a result, premature water breakthrough may be realized. This leads to the concept of viscous fingering. Since water, a less viscous fluid, is used to displace oil, a more viscous fluid, the resulting displacement will suffer from viscous fingering of the low viscosity fluid into and ahead of the high viscosity fluid. This of course reduces the displacement efficiency.

The higher the oil-water viscosity ratio, the lower is the percentage of oil recovery. High oil viscosities tend to retard the rate at which capillary forces can deplete tight sections of a porous medium. Therefore, viscosity indirectly affects recovery through the rate factor(6).

EXPERIMENTAL APPARATUS:

Three basically different cores were used in the laboratory experiments. Waterflood tests were performed on a limestone core, on an unconsolidated sand pack, and on two alundum cores. Properties of these cores are presented in Table 1.

TABLE 1

CORE PROPERTIES

Core	Length cm	Diameter cm	Porosity %	Ave. Water Permeability md
Limestone A4-28	17.27	8.89	11.36	1.04
Unconsolidated Sand Pack	74.93	7.62	34.0	42,000
Alundum A1	33.81	2.54	23.6	378
Alundum A2	45.56	2.54	26.8	480

The limestone core was non-homogeneous and variations of properties along the core were noticeable. The non-uniformity of the limestone core should be emphasized.

Distilled water was used as the displacing phase and four different viscosity oils were used as the displaced phase. The CWO base oil (viscosity of 1.637 cp at 76° F)

was used in a majority of the experiments. The waterfloods performed and the corresponding test conditions are shown in Table 2. Care was exercised to ensure that no polar compounds or surface active agents were present. This was achieved by filtering the oil through silica gel prior to conducting a test.

Ottawa 20-40 mesh sand was used to form the unconsolidated sand pack. A lucite tube was employed as a container. A porous bronze plate was inserted at each end of the pack to prevent any sand movement into the injection and discharge ports of the lucite flanges.

The Swan Hills limestone core was mounted in 5½ inch steel oil well casing and sealed with an epoxy resin poured between the inner wall of the casing and the outer circumference of the core. This ensured a complete seal between the casing and the core and prevented any fluid bypassing or migrating from the core. The fluid was thereby confined to the pore space. The ends of the core were cut, ground and sanded flush with the end of the casing. Care was taken not to contaminate the faces of the core. The core was then assembled between two high pressure steel flanges. The portion of the flange inserts that were in contact with the core faces were grooved concentrically and radially to enable the injected fluid to cover a greater cross-sectional area

TABLE 2

Waterfloods Performed and Test Conditions

Water- flood Series	Core	Oil Used	μ_o/μ_w	Ave. Connate Water Sat'n. %	Rate S_{cw} Estab. cc/hr.	Test Temp. °F	Wettability
A	Limestone A4-28	Diesel	1.5	40.5	60	70	Water-Wet
B	Limestone A4-28	Swan Hills Crude	4.38	40.5	60	70	Water-Wet
C	Unconsolidated Sand Pack	Diesel	1.5	21.8	320	70	Water-Wet
D	Alundum A1	CWO Base	1.82	15.46	120	76	Water-Wet
E	Alundum A1	CWO Base	1.82	14.19	60	76	Water-Wet
F	Alundum A1	CWO Base	1.82	12.6	240	76	Water-Wet
G	Alundum A1	CWO Base	1.82	0	---	76	Water-Wet
H	Alundum A2	Hago Fill	6.61	22.1	120	76	Water-Wet
J	Alundum A2	Hago Fill	6.61	22.4	120	76	Oil-Wet

of the core. This was done to minimize the inlet end effect.

The alundum cores were mounted in a similar manner also using the epoxy resin. The Alundum A1 core was mounted in a 3½ inch lucite cylinder. This enabled a visual examination on the durability of the filler material during testing operations. However, the use of lucite as a casing limited the range of pressures that could be used. It was unsafe to employ pressures higher than 150 p.s.i. with the lucite apparatus. Since higher pressure drops would be encountered by the use of more viscous oils, the Alundum A2 core was mounted in 3 inch seamless pipe using steel flanges. The flanges were grooved as before.

Figure 6 is a schematic diagram of the test apparatus. A Ruska proportioning displacement pump calibrated to 0.01 cc was used. Constant injection rates of 2.5 cc/hr to 1120 cc/hr could be obtained. A constant temperature air bath cabinet was employed to ensure no temperature variation during any given test and also to assist in the various drying operations.

A Heise pressure gauge with a range of 0 to 250 psig was used to measure the upstream and downstream pressures across the high permeability cores. A 0 to 3000 psig Heise gauge was used when conducting tests on the limestone

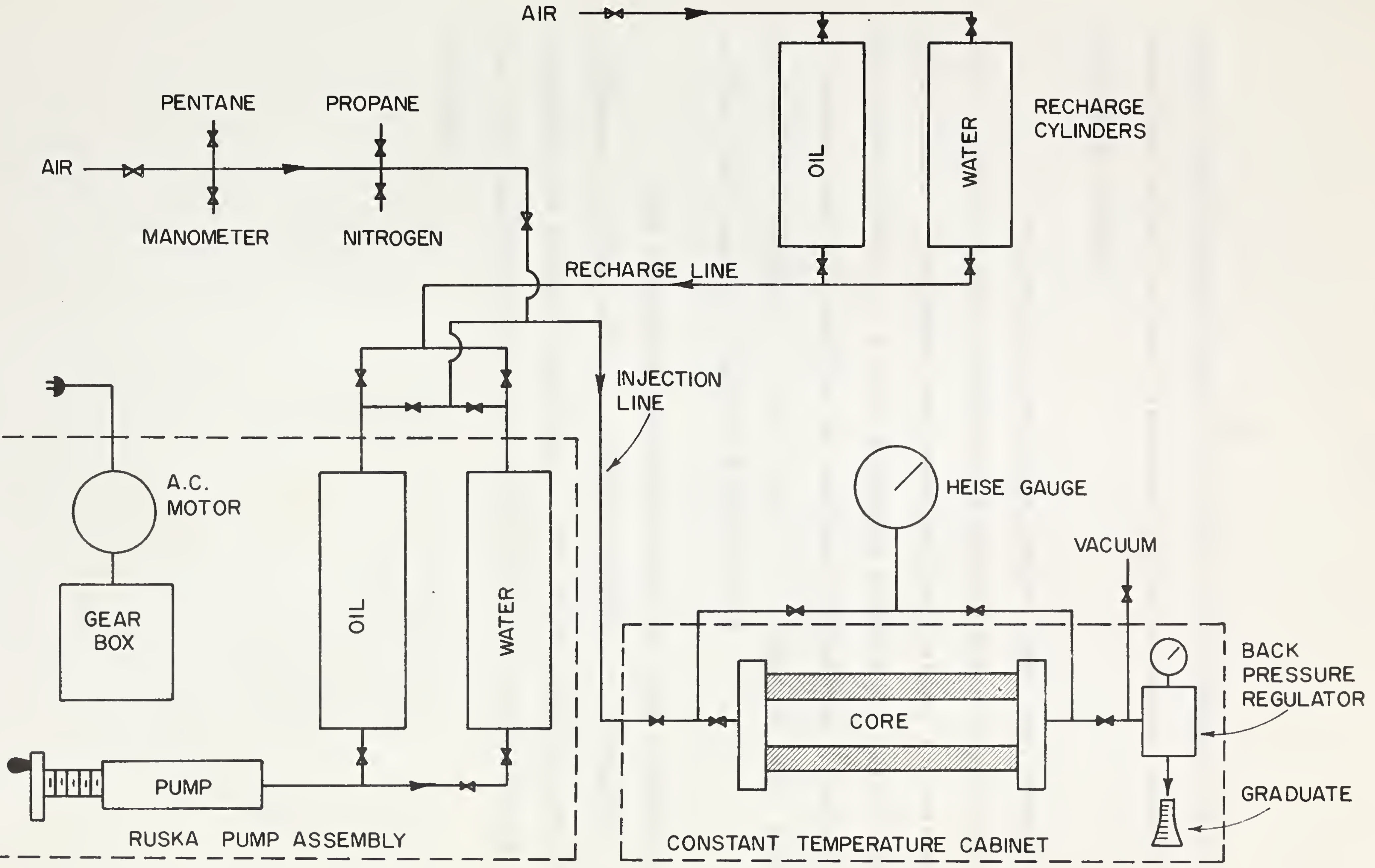


FIG. 6. DIAGRAM OF TEST APPARATUS.

core. The pressure taps were placed approximately 1½ inches from the injection and discharge ports to ensure accurate pressure readings.

A vacuum line could be hooked into the downstream end of the core for evacuation purposes prior to saturation operations. Provision was made for regulating and measuring the core effluent. A back pressure regulator, loaded from a nitrogen source, provided a constant downstream pressure. Graduated cylinders of 10 cc and 25 cc capacity were used to collect and measure the fluid production.

The apparatus was manifolded so that a number of different fluids could be flushed through the cores for the cleaning and drying operations. All flow lines in the system were constructed of 1/8 inch stainless steel tubing and fittings.

EXPERIMENTAL PROCEDURE

Preliminary tests on small samples taken from the cores to be used showed a pronounced preferential wettability as evidenced by spontaneous water imbibition upon immersion of oil saturated samples into water. Thus the cores were assumed to be preferentially water-wet.

In preparation for a displacement test, a core was thoroughly cleaned and dried. The core was flushed with five to six pore volumes of commercial n-pentane. A quantity of propane was then injected under a tank pressure of about 140 psig with a back pressure of about 80 psig being maintained to keep the propane as a liquid in the core as long as possible. Drying was accomplished by flowing air and later, nitrogen, through the core for a period of three days.

The core was then evacuated and later, saturated with distilled water (except for series G waterflood where connate water saturation was zero percent) and the porosity determined. The water permeability was obtained by measuring the water throughput and the time of flow for various pressure drops. Darcy's equation for linear incompressible flow was then used to calculate the water permeability. The form of Darcy's equation is as follows:

$$k = \frac{q \mu L}{A \Delta P}$$

where: k - permeability (darcies)

q - flow rate (cc/sec)

u - viscosity (cp)

L - length of flooded system (cm)

A - cross-sectional area (cm^2)

ΔP - differential pressure (atm)

The initial oil saturation and the connate water saturation were established by oil flooding the core with five to six pore volumes of oil. All initial conditions, for a given waterflood series, were established under identical circumstances.

Waterflood tests were then performed at various rates. After a given test in a series, the core was again flooded with five to six pore volumes of oil in preparation for the next test (except in series B and G waterfloods). The core was cleaned and dried in between each successive test for series B and G waterfloods. This was done in an attempt to have better control over the establishment of the connate water saturation in the series B waterflood. In the series G waterflood, the tests were conducted with a one-hundred percent initial oil saturation which necessitated the removal of the remaining fluids in order to prepare for the next test.

A solution mixed in the proportion of 5 cc linoleic acid and 250 cc methyl alcohol was injected into the Alundum A2 core and allowed to remain in the core for 24 hours. The solution was flushed out of the core by flooding with eight pore volumes of water. This treatment changed the wettability of the system from water-wet to oil-wet and thus established a thin water repellent film on the alundum surface. The degree of oil-wettability was uncertain. However, the oil did become the wetting phase. The series J waterflood tests were then performed on the core. The linoleic acid-methyl alcohol solution was used instead of a more stable treatment using a silicone compound. High temperatures of 150° F plus, are required when treating with various silicone compounds. Since the cores were mounted in an epoxy resin, temperatures higher than 120° F could not be tolerated; otherwise, failure in the resin may result.

A back pressure of approximately 11 psig was maintained during all flooding operations. Also, throughout the tests, the temperature of the cores was controlled thermostatically in the air bath.

The recoveries of oil at water breakthrough and at WOR = 20:1 were used with scaling coefficients(24) as correlating parameters in all tests.

RESULTS AND DISCUSSION

Numerous waterfloods were performed on the cores at rates ranging from 10 cc/hr to 840 cc/hr. The results of each series of tests are presented in the form of correlating oil recoveries to water breakthrough and to WOR = 20:1 with scaling coefficients. The parameters of concern were: oil viscosity, porous medium, connate water saturation, and wettability. In each series of tests, the length of system and the four previously mentioned parameters were constant; water injection rate was the variable. In some instances oil recovery increased with injection rate, but in other cases oil recovery decreased with injection rate.

Figure 7 illustrates the results of the tests conducted on the Limestone A4-28 core. Series A waterflood was performed using an oil-water viscosity ratio of 1.5 while series B waterflood was performed using a higher oil-water viscosity ratio of 4.38. The series A waterflood exhibited a steady decrease in oil recovery to water breakthrough with increased injection rates. The oil recovery to WOR = 20:1 increased slightly, remained essentially constant, and then decreased slightly with increased injection rates. Subordinate recoveries increased with rate.

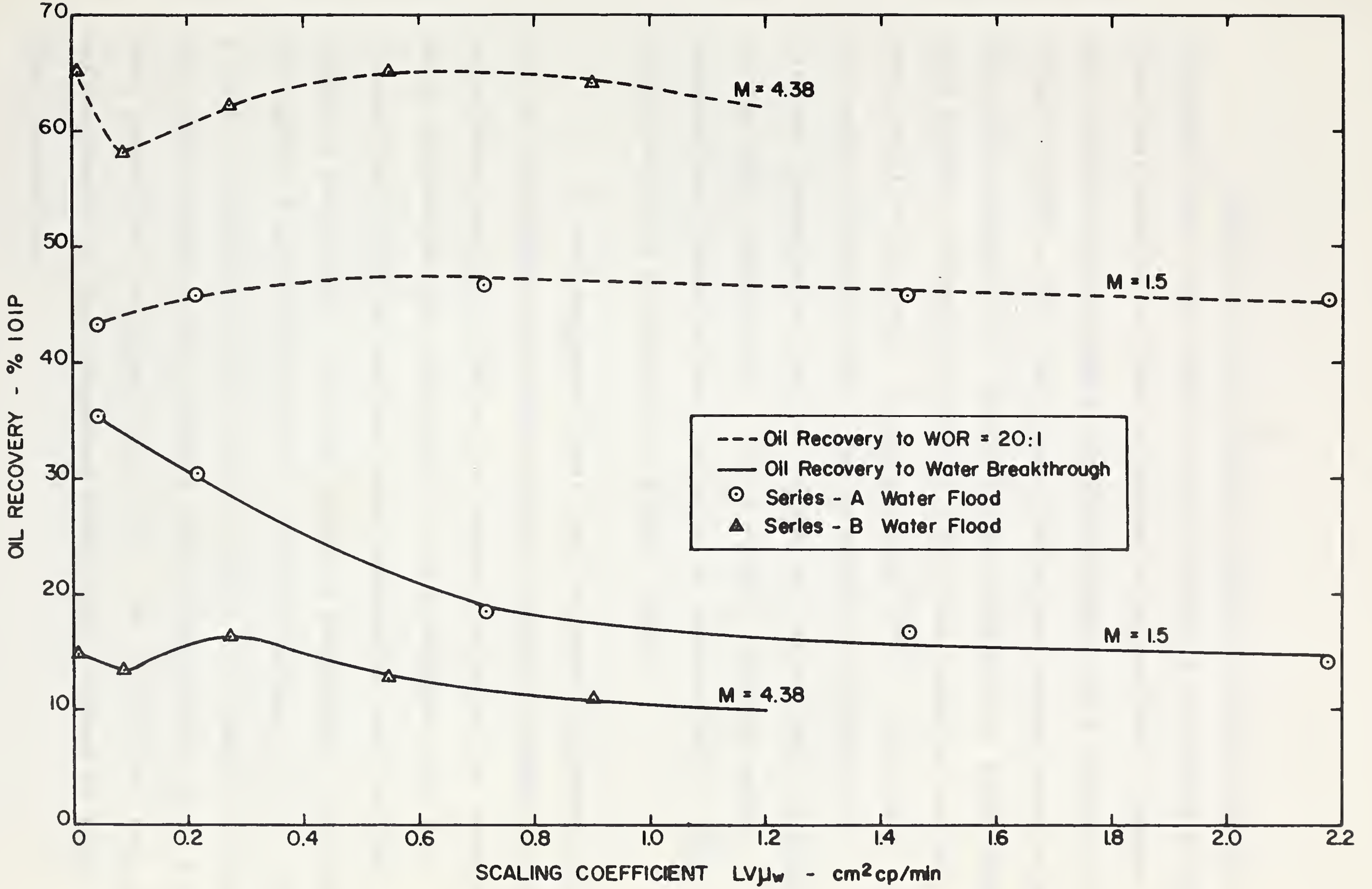


FIG. 7 THE EFFECT OF OIL-WATER VISCOSITY RATIO ON OIL RECOVERY IN A LIMESTONE, PREFERENTIALLY WATER - WET SYSTEM.

Except for the peculiar behavior at the very low flooding rates, the trend in oil recoveries of series B waterflood was similar to that of series A waterflood. However, the breakthrough recovery was considerably less and the recovery to WOR = 20:1 was greater when performing tests with the more viscous oil. The lower oil recovery to breakthrough with higher oil-water viscosity ratio was expected and has been verified by other investigations(6,18). The higher the oil-water viscosity ratio, the greater the tendency for viscous fingering of the low viscosity water into and ahead of the high viscosity oil. As a result, earlier water breakthrough occurred when using more viscous oils. This effect was more pronounced at higher rates.

It was suggested that the increased ultimate recoveries in the floods conducted with the higher oil-water viscosity ratio were partially due to the manner in which the connate water saturation was determined. The limestone core was cleaned and dried in between each successive test for the series B waterflood. For the series A waterflood, the core was merely flooded with five to six pore volumes of oil after a test in preparation for the next test. It should be pointed out that unusually high connate water saturations of 40.5 percent prevailed throughout the tests. It is believed that the heterogeneity of the limestone system contributed to this high saturation.

Small subordinate recoveries at low rates were observed and were attributed to the effluent end effect. This has been verified by Kyte and Rapoport(17). Water production was restricted for a short period of time at the outlet face during low rates of water injection and thus actual water breakthrough occurred sometime after water arrival.

The effluent end effect occurs because of the discontinuity in capillary pressure across the boundary when the flowing fluids leave the core. An excessive water saturation at the outflow face and a delay in the water breakthrough results. Water will not leave the core when it first reaches the outlet face but will accumulate inside and only oil will be produced. Water will be produced only when sufficient pressure has built up in the water phase to exceed that of the oil phase.

The results of series C and D waterfloods conducted on the unconsolidated sand pack and on the Alundum A1 core using oil-water viscosity ratios of 1.5 and 1.82 respectively, are presented in Figure 8. As was the behavior in the previous floods, the effect of injection rates was less pronounced for oil recovery at WOR = 20:1 than for oil recovery water breakthrough. However, the oil recovery to water breakthrough curves exhibited a characteristic "S"

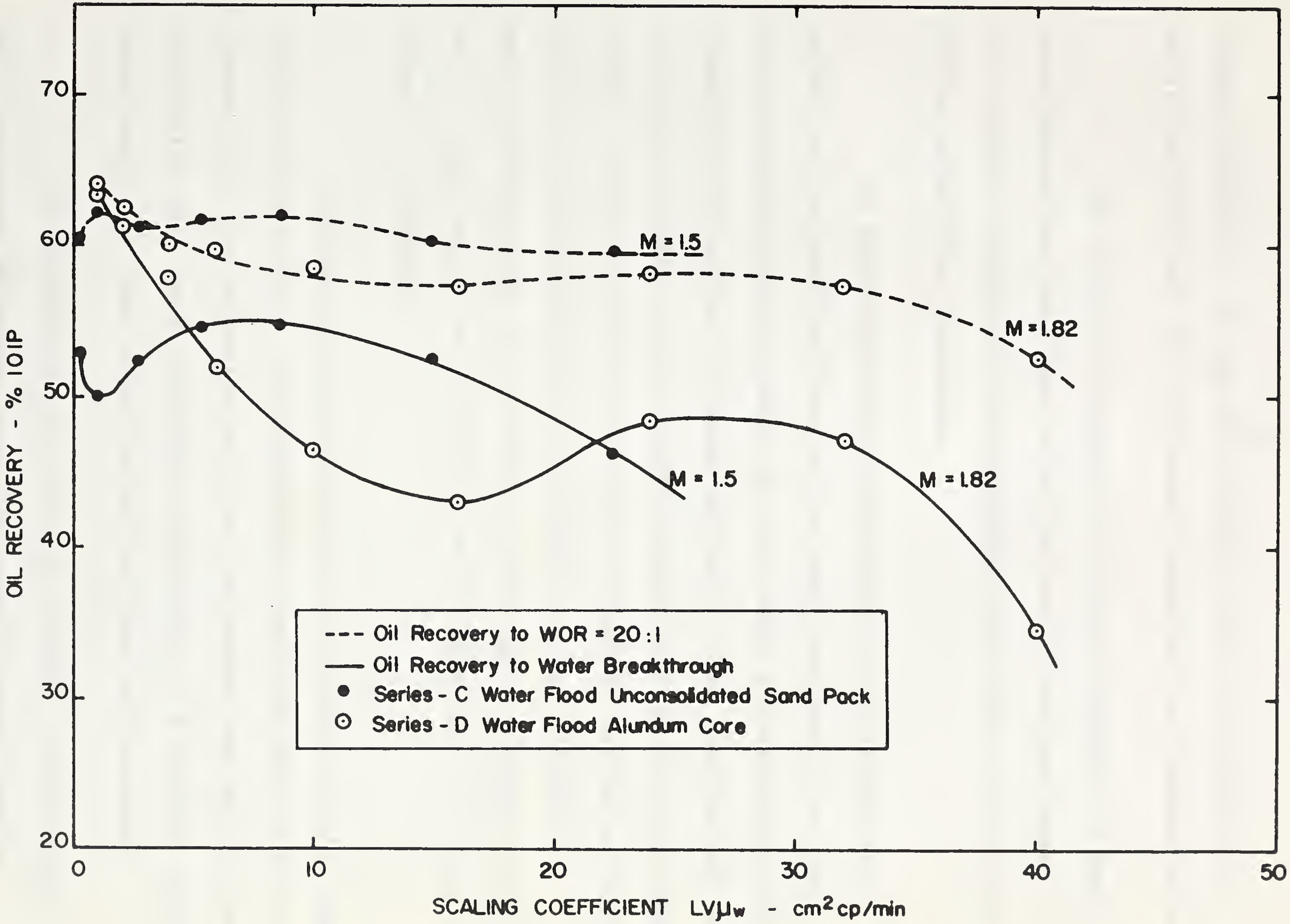


FIG. 8. RELATION BETWEEN OIL RECOVERY AND SCALING COEFFICIENT IN HOMOGENEOUS, PREFERENTIALLY WATER-WET SYSTEMS.

shaped behavior. As can be observed later, this type of curve was obtained for all tests conducted on alundum cores.

The initial decrease in the oil recovery to water breakthrough at the lower injection rates was attributed to the combined effect of the capillary outlet end effect and of the imbibition phenomena.

As was previously discussed, the capillary end effect at the outflow face of the core resulted in a high water saturation and a delay in the water breakthrough time compared to the time of water arrival. This contributed to the high oil recovery to water breakthrough at low injection rates. As the injection rate was increased, the water saturation at the downstream end of the core was reduced at water breakthrough as a result of the higher pressure gradients. This caused an earlier water breakthrough and thus a lower oil recovery.

Flooding rates sufficiently low permitted the imbibition of water into low permeability sections by capillary forces. As the injection rate was increased the effects of imbibition were less pronounced resulting in a smaller area being swept and thus contributing to lower oil recovery.

The increased oil recovery to water breakthrough with increased injection rate indicates a trend towards

stabilization. In this region the outlet end effects and the inlet end effects are minimized.

The oil recovery to water breakthrough decreased sharply at very high injection rates and was attributed partially to the inlet end effect and partially to the viscous fingering phenomena.

As a result of the inlet end effects, capillary forces within the core tend to distribute the injected water over the cross-sectional area. At low rates these forces are significant and they prevent deviation from linear behavior. However, at the high rates these forces are small and non-linear flow may have occurred. Thus the low recoveries at high rates may have been due to non-linear flow.

It was felt that cores with smaller diameters would minimize the inlet end effect. The alundum cores (2.54 cm dia.) had considerably smaller diameters than did the unconsolidated sand pack (7.62 cm dia.) and the limestone core (8.89 cm dia.) and thus, were advantageous to this study.

The factors influencing or initiating fingering are the following: rock permeability, pore space geometry, water injection rate, and the oil-water viscosity ratio. In a waterflood test (where the oil-water viscosity is greater than unity) the resulting displacement would suffer from

viscous fingering of the lower viscosity water into and ahead of the higher viscosity oil. This, of course, would reduce the displacement efficiency.

The heterogeneity of the porous medium can lead to considerable difficulty in the maintenance of a uniform flood front. Also, a variation in permeability in the system would contribute to the formation of "fingers". Although the mass rate of flow was constant, the velocities through the lower permeability sections with smaller sized pore channels will be greater. As the water injection rate was increased, the fingering phenomena would be more pronounced.

The higher the oil-water viscosity ratio, the greater would be the tendency for the water to "finger" ahead of the oil. Also, high oil viscosities tend to retard the rate at which capillary forces can deplete tight sections of the porous medium.

It was observed that oil recoveries for the unconsolidated sand pack and the alundum core were in the same order of magnitude while the oil recoveries for the limestone core were considerably lower (at similar oil-water viscosity ratios). The latter case was as low as one-third the oil recovery as in the former case. This may be expected since waterflood behavior is also a function of the nature of the

porous medium. In the first case the unconsolidated sand pack and the alundum core were essentially homogeneous systems, while in the latter case the limestone core was a heterogeneous system.

Figures 9 and 10 demonstrate the influence of connate water saturations on oil recovery to water breakthrough and on oil recovery to WOR = 20:1 respectively. Tests performed in waterflood series D, E, F, and G differ only in regard to the connate water saturation present (see Table 2).

It was believed that the connate water saturation was mobile in the series D waterflood. This concept would contribute to the early water breakthrough at the higher rates, resulting in a lower oil recovery to water breakthrough as compared to oil recovery to WOR = 20:1. An attempt was made to decrease the connate water saturation for the next series of tests. It was found that the technique of altering the oil flooding rates at which the connate water saturation was determined would decrease this saturation slightly. Tests performed at the successively lower connate water saturations experienced greater oil recovery to water breakthrough while the oil recovery to WOR = 20:1 remained essentially the same. The effect of connate water saturation on oil recovery in these results may have been due to the influence of the initial saturation distribution.

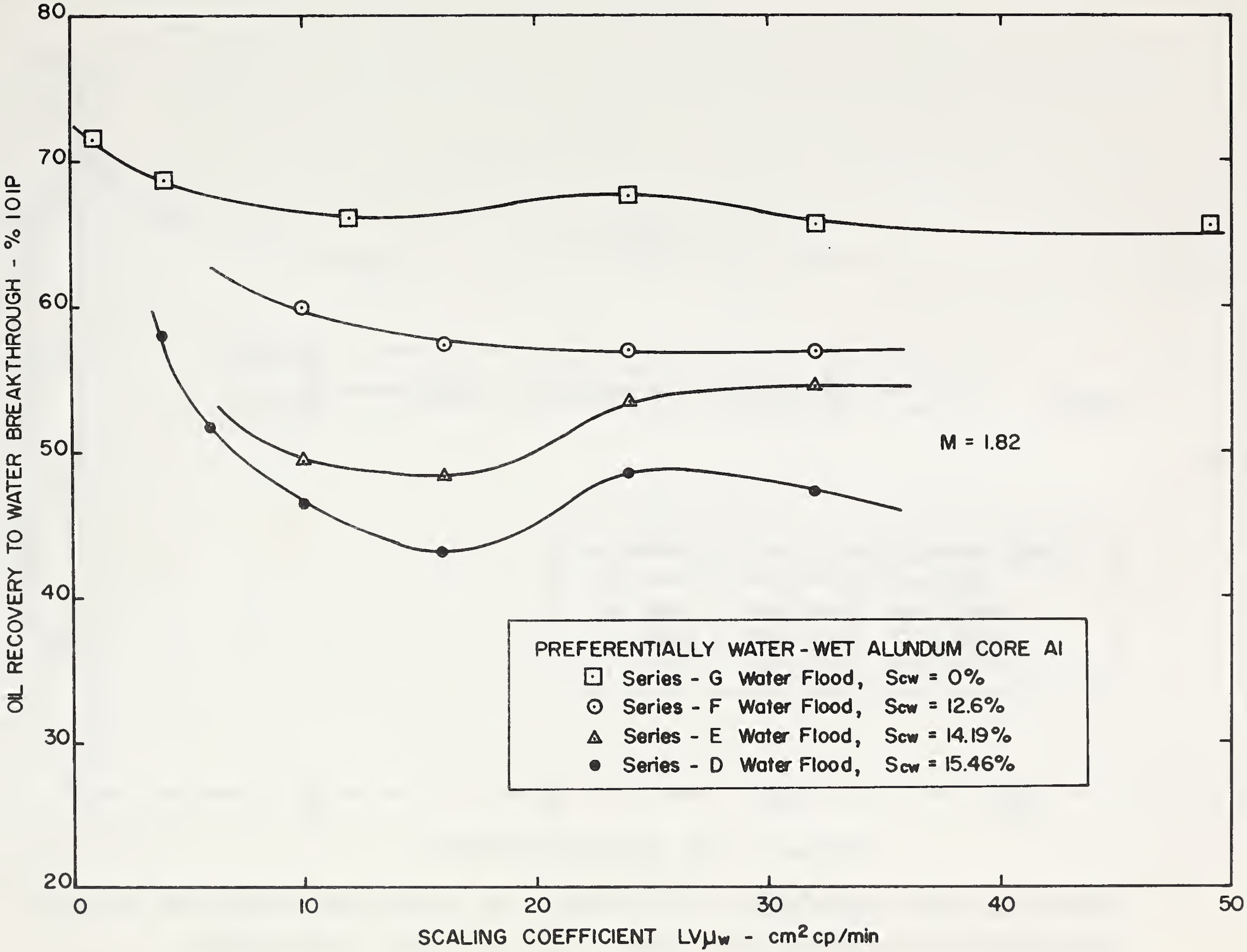


FIG. 9. RELATION BETWEEN OIL RECOVERY TO WATER BREAKTHROUGH AND SCALING COEFFICIENT WITH CONNATE WATER SATURATION AS PARAMETER.

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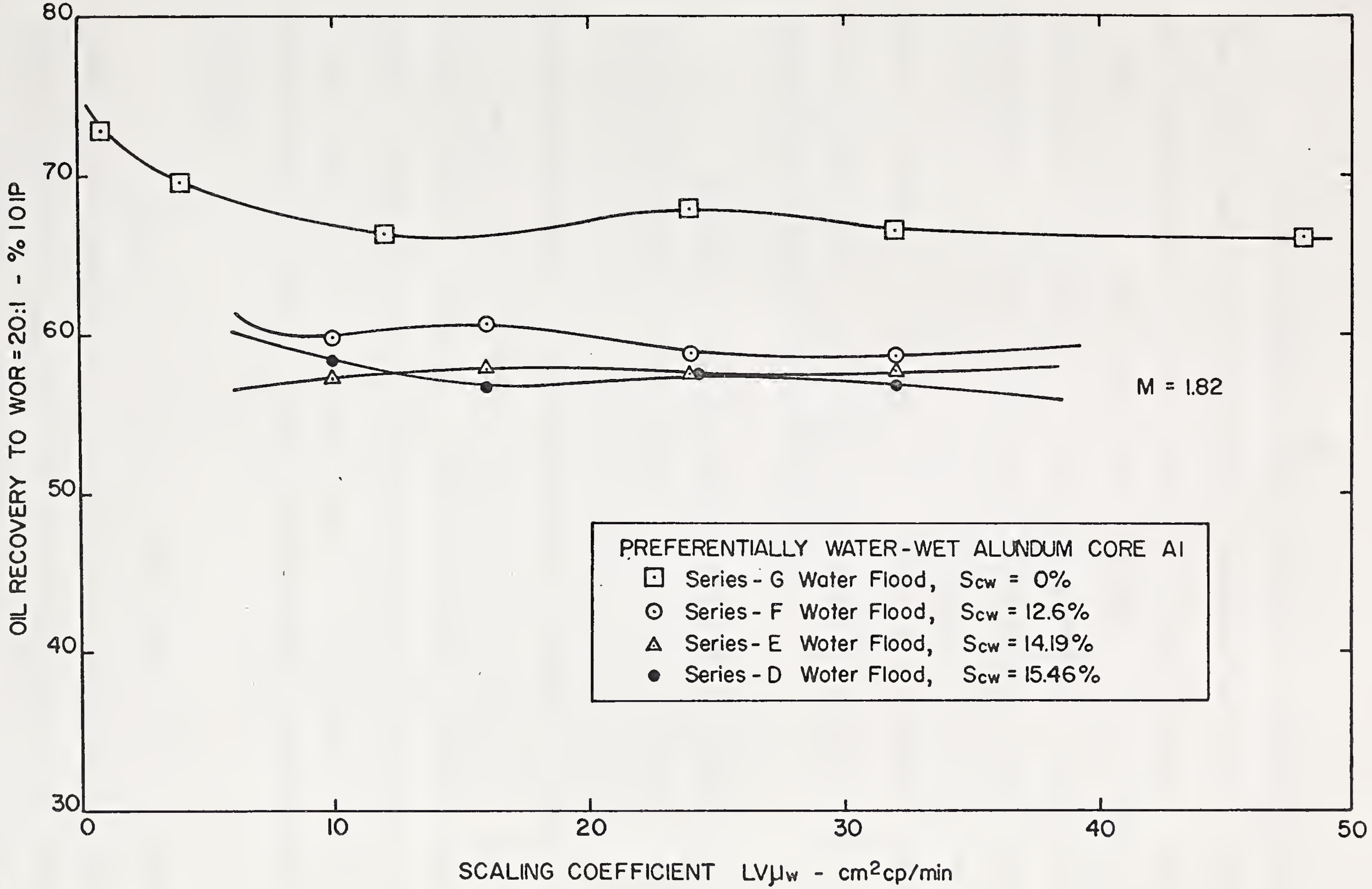

FIG. 10. RELATION BETWEEN OIL RECOVERY TO WOR = 20:1 AND SCALING COEFFICIENT WITH CONNATE WATER SATURATION AS PARAMETER.

It was suggested that prior to a waterflood test, the core should be alternately flooded with water and with oil to bring about stable equilibrium conditions. The test should be conducted only after constant values have been achieved for residual oil saturation and for connate water saturation. It was felt that this procedure would partially overcome the influence of the initial saturation distribution on oil recovery. The manner in which the connate water was established is of the utmost importance in the correct interpretation of laboratory waterfloods.

Series G waterflood was conducted using a zero percent connate water saturation; or in other words, a one-hundred percent oil saturation prior to each flood. The results indicated a more stabilized behavior for both the oil recovery to water breakthrough and for the oil recovery to WOR = 20:1. Moreover, the subordinate recovery was essentially negligible and contributed only a one percent increase of the initial oil in place towards the ultimate production. High water-oil ratios resulted immediately after water breakthrough.

Figure 11 illustrates the effect of oil-water viscosity ratio change on oil recovery in an alundum, preferentially water-wet system. Series D waterflood was performed using an oil-water viscosity ratio of 1.82 while series H

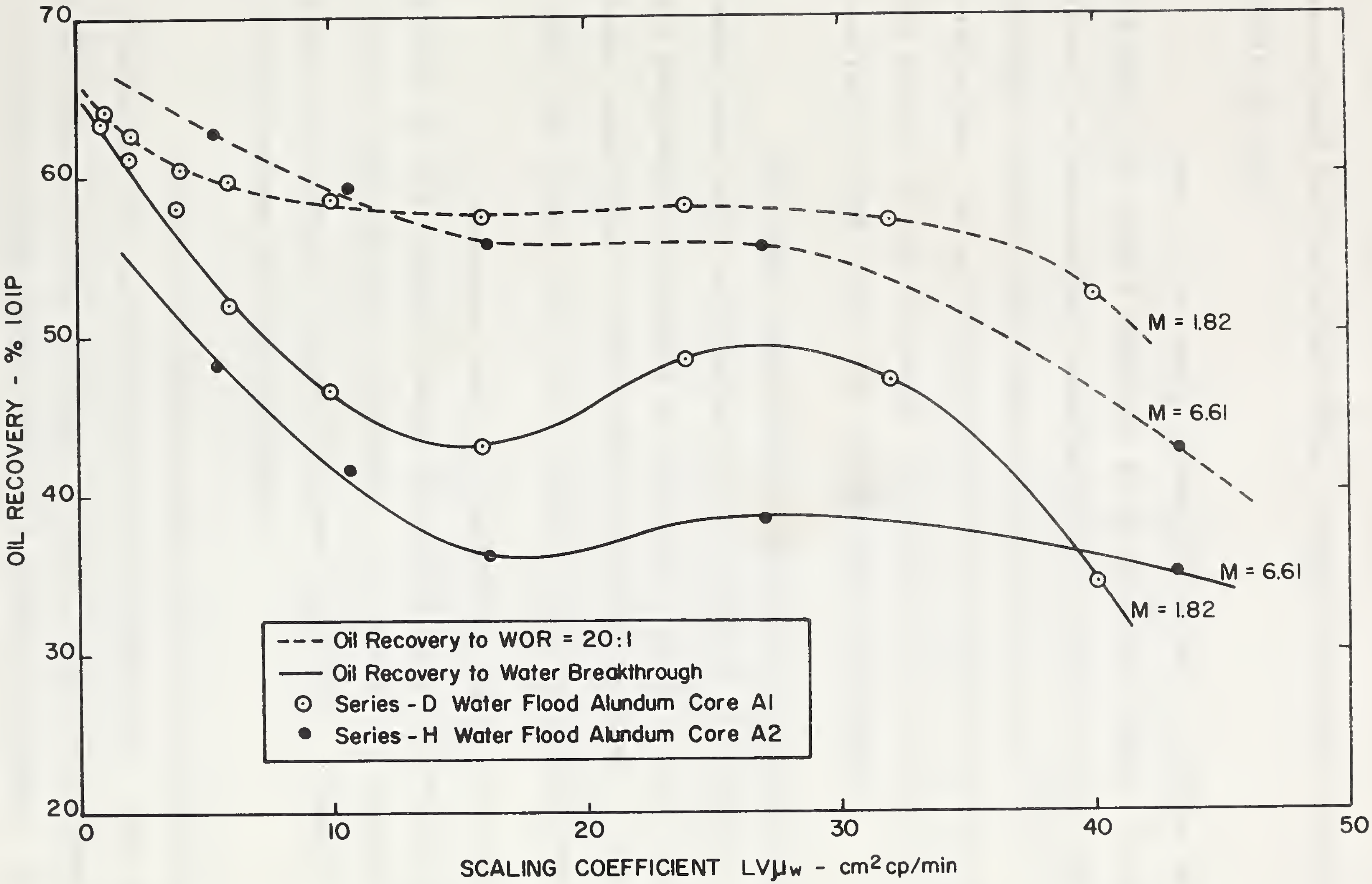

FIG. 11. THE EFFECT OF OIL-WATER VISCOSITY RATIO ON OIL RECOVERY IN A HOMOGENEOUS, PREFERENTIALLY WATER-WET SYSTEM.

[illegible]

waterflood was performed using a higher oil-water viscosity ratio of 6.61.

The oil recovery curves exhibited a similar characteristic "S" shaped behavior as in previous tests. As predicted by theoretical considerations, earlier water breakthrough occurred when using the more viscous oil(6,18). Also, this effect was more pronounced at the higher injection rates. The effect of the oil-water viscosity ratios on the oil recovery to WOR = 20:1 was essentially negligible.

The small subordinate recoveries experienced at low rates were again attributed to the effluent end effect. The oil recoveries decreased at the high injection rates and were again considered to have been the combined result of the inlet end effect and of the viscous fingering phenomena.

A treatment was incorporated to change the wettability of the alundum system from water-wet (hydrophilic) to oil-wet (hydrophobic) conditions. It should be pointed out that the degree of oil-wettness was uncertain. However, the oil did become the wetting phase.

Figure 12 illustrates the effect of wettability reversal on the oil recovery in an alundum core. The results indicated that lower ultimate recovery would be obtained in an oil-wet system rather than in a water-wet system. The

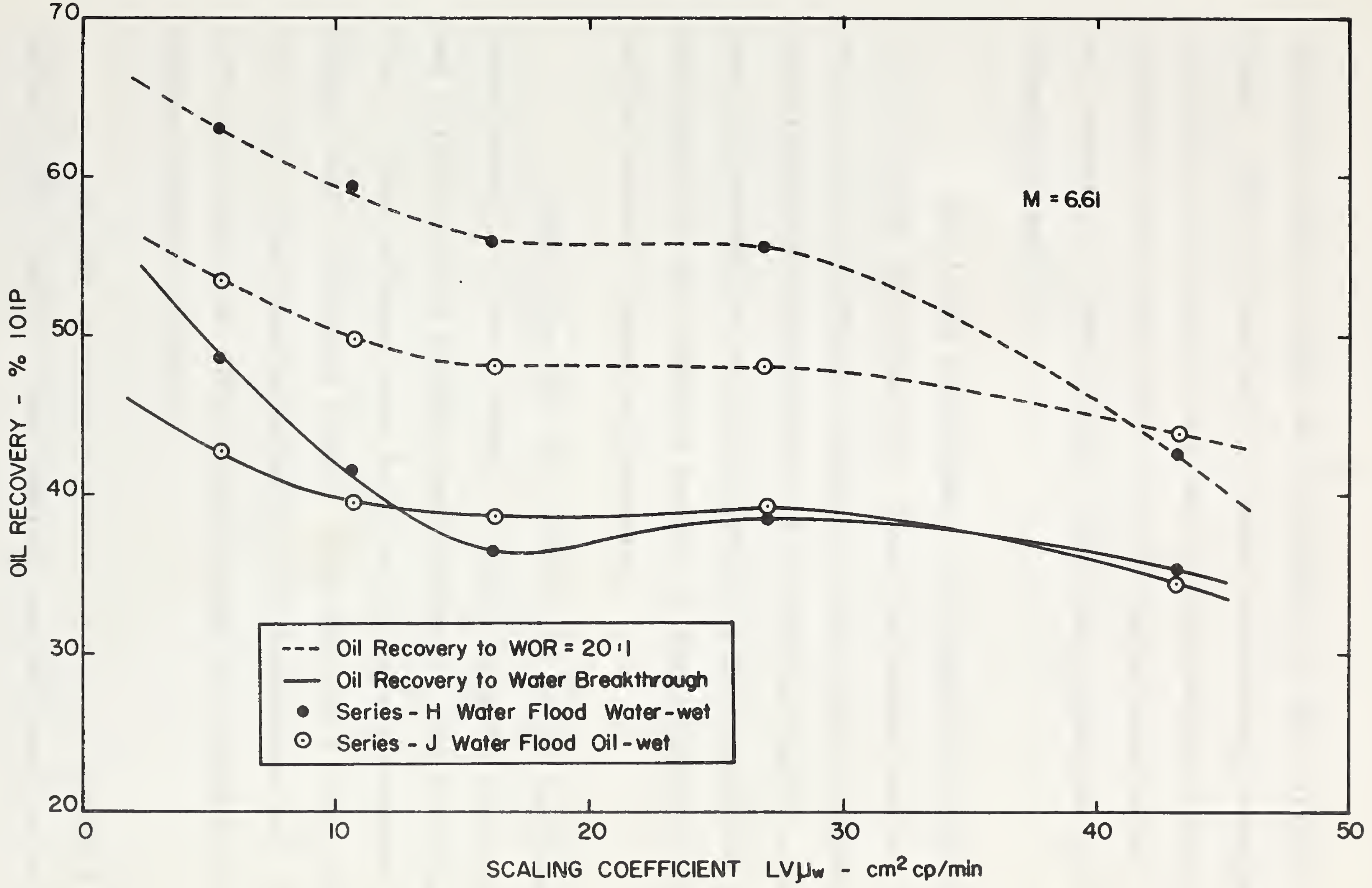

FIG. 12. RELATION BETWEEN OIL RECOVERY AND SCALING COEFFICIENT IN ALUNDUM, FOR OIL-WET AND WATER-WET CONDITIONS.

[illegible]

difference was as much as ten percent of the initial oil in place. The oil recovery to water breakthrough remained essentially the same for the two systems except at very low injection rates where the oil-wet system experienced lower oil recovery. These results have been supported by other investigations(7).

The large subordinate oil production experienced in both cases was expected. Since the tests were performed using a high oil-water viscosity ratio, early breakthrough and significant subordinate oil production would occur(6,18). Low oil recoveries at high injection rates prevailed and were attributed to the combined result of the inlet end effect and of the viscous fingering phenomena.

Based upon all the waterflood tests performed, experimental evidence seemed to indicate that the capillary end effects at the outlet face influenced the flooding behavior. These effects were found to be less pronounced at higher water injection rates. This was due to the fact that the water saturation gradient at the downstream end of the core was reduced at water breakthrough as a result of the higher pressure gradients.

It was observed that oil recovery decreased at high rates in all tests. This behavior was believed to be the

combined result of the inlet end effects and of the viscous fingering phenomena. Although at high rates the oil recovery should increase because of the stabilization process, it would decrease because of viscous fingering. A flood may be stabilized when the capillary pressure gradient in the direction of flow is small compared to the imposed pressure gradient.

The possibility of turbulence and inertial effects influencing flow behavior in limestone cores should be examined. Although there was a constant mass rate of flow into cores, the velocities may have been different, i.e.: in a heterogeneous system the flow paths are very irregular. Therefore, the inertial effects may have been quite appreciable. Conditions are much more favorable for turbulent flow in heterogeneous limestone systems(28) than in homogeneous sandstone systems. This is a result of the wide variation in the size, shape, and distribution of the pores and rough, irregular pore surfaces in a limestone type system.

The relation between the cumulative oil recovery and the pore volumes of water injected for waterfloods conducted on the alundum cores was demonstrated in Figures 1-B, 2-B, 3-B, 4-B, 5-B, and 6-B in appendix B. The curves gave an indication of the subordinate oil recovery and the extent of the water-oil ratios for the corresponding tests.

Figure 7-B (in appendix B) illustrates the change in differential pressure as a flood progresses through the alundum core. The shape of this curve is typical for all tests. The reason for the initial increase in pressure as water advances in the core was due to the fact that the core was at a lower pressure than the injection pressure. The resulting decrease in pressure was attributed to the more favorable relative permeability to water as the water saturation increased.

The following tests were performed to obtain a qualitative order of magnitude of the capillary pressure and the water-oil relative permeability ratio characteristics of the Alundum A1 core.

A capillary pressure characterization curve was determined. The data was obtained by employing the mercury injection method(27) and the results correlated to Leverett's J-Function (see Tables 10-A, 11-A). Figure 13 shows the experimental curve for alundum compared to Leverett's curve for alundum. For a given wetting phase saturation, the experimental curve has lower J-Function values than Leverett's curve. The difference in agreement was approximately twenty per cent.

A calculation by the unsteady state method(10) was

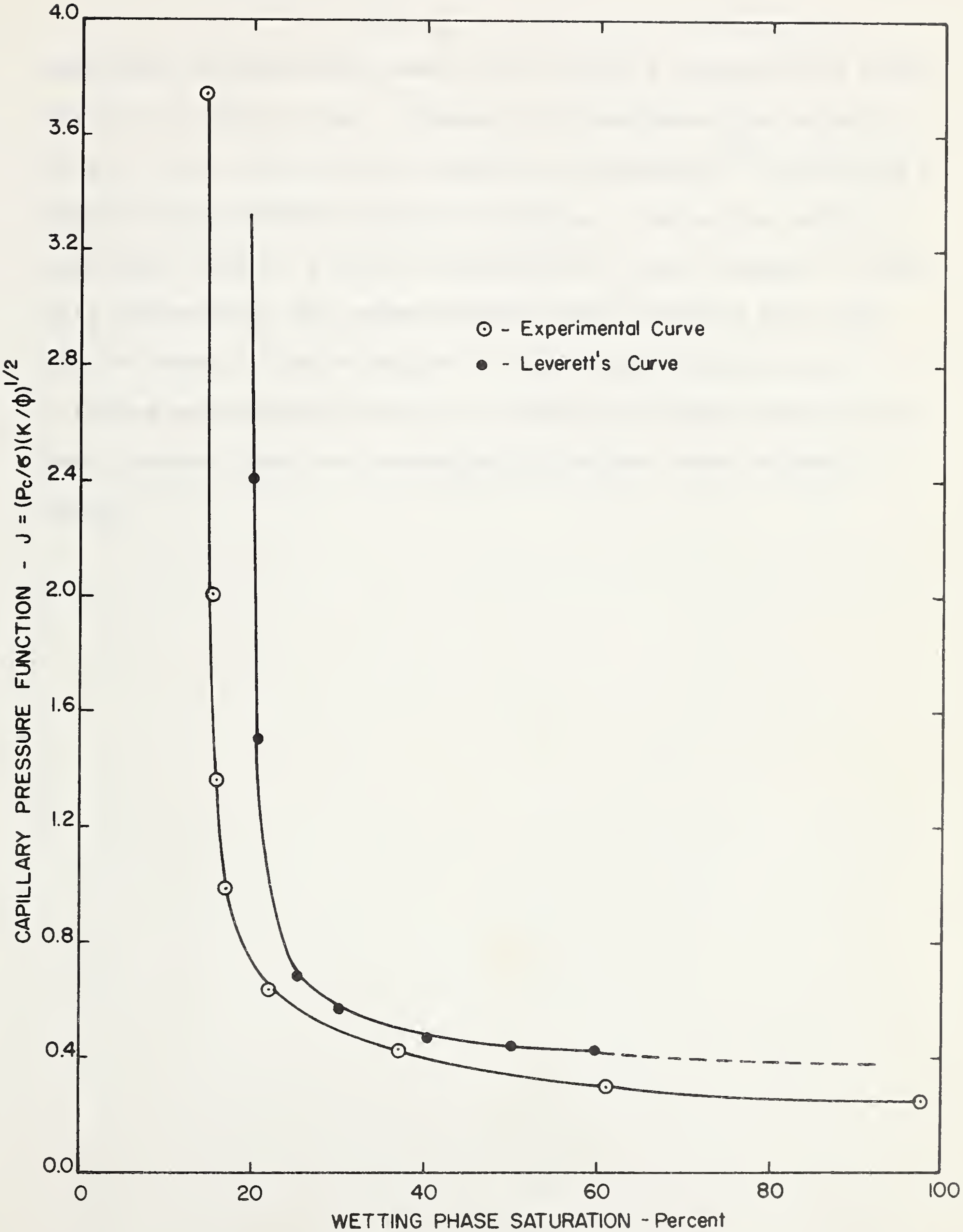

FIG. 13. CAPILLARY PRESSURE RESULTS COMPARED TO LEVERETT'S J-FUNCTION FOR ALUNDUM CORE A1.

performed to obtain the water-oil relative permeability ratio curve (see Table 12-A). Figure 14 illustrates the experimental curve for alundum compared to Calhoun's(4) curve for a typical consolidated sandstone system. The curves were in agreement down to a water saturation of sixty percent. Below this saturation, the experimental curve deviated from Calhoun's curve. This resulted in experimental water-oil relative permeability ratios in excess of three hundred percent greater than the corresponding values from Calhoun's curve.

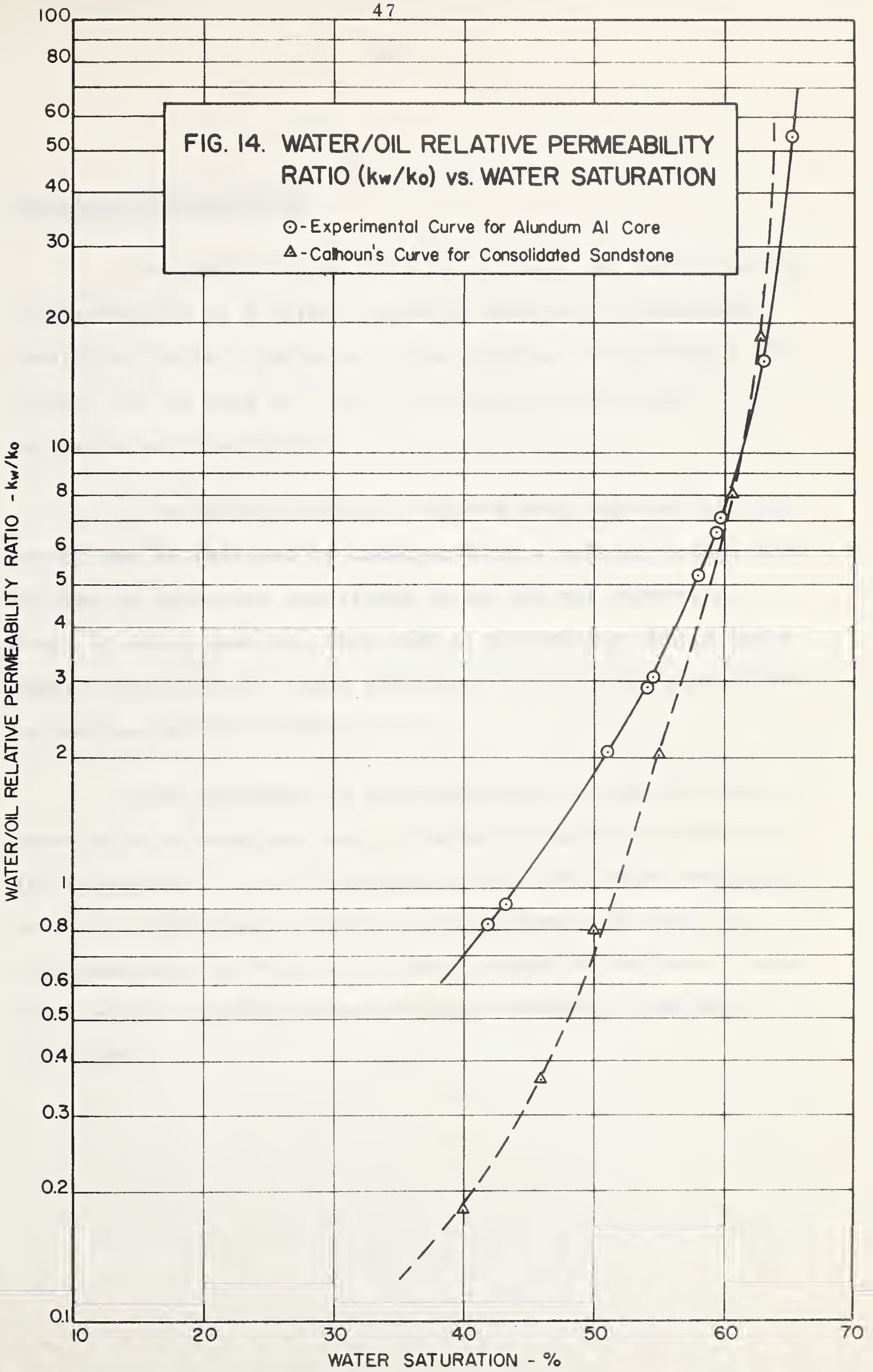

FIG. 14. WATER/OIL RELATIVE PERMEABILITY RATIO (kw/ko) vs. WATER SATURATION

PRACTICAL APPLICABILITY

It should be possible to evaluate the waterflooding susceptibility of a given reservoir material by laboratory model flow tests. Moreover, these studies, if carefully conducted, can be used for field performance predictions with assurance as to accuracy.

The present results indicate that improved oil recovery may be realized by incorporating a wetting change from oil-wet to water-wet conditions in an oil-wet reservoir. Also, it seems possible that such a wettability change could improve the over-all sweep efficiency by increasing capillary attraction for the invading water.

The influence of heterogeneities on the flooding behavior of a reservoir can be deduced from flow studies in the laboratory. It is important to have the water advancing at such a rate that it penetrates and expels oil from the tight sections as well as the more permeable sections. Thus, the highest injection rates are not necessarily the most efficient.

SUMMARY AND CONCLUSIONS

Accounting for experimental oddities in determining the floodability of specific reservoir rocks has not been adequately considered by the practicing engineer. The principle barrier to generalizations from laboratory model studies has been the lack of control over certain variables which greatly influence waterflood behavior. There is a need for differentiating between the in situ characteristics of water-oil displacement inside the porous rock and the secondary end effects.

Based upon the results obtained the following observations have been made:

1. Before utilizing laboratory results for field evaluations, consideration must be given to the stabilization process and to the inlet and outlet end effects.
2. Long cores should be used where at all possible in studies to ensure stabilized conditions and to minimize the "end" effects.
3. The scaling coefficient ($LV\mu_w$) can be conveniently used as a basis for correlation of waterflood recoveries if wettability conditions are constant for the porous medium under consideration. However, the utilization of the coefficient for correlation of results in limestone systems should be modified to account for the heterogeneity

of the system.

4. Laboratory floods should be compared at high water-oil ratios and at high rates where stabilization conditions exist and the secondary end effects are less pronounced.
5. Reversing the wettability of a homogeneous system from water-wet to oil-wet will result in a decrease in ultimate oil recovery.
6. Lower oil recovery to water breakthrough will result when using more viscous oil for a flood.
7. Increased displacement efficiencies and a more stabilized behavior will result when using no connate water saturation for a flood.

RECOMMENDATIONS

Further investigation into the factors which influence oil recovery by waterflooding is necessary before laboratory results can be applied to field performance predictions with assurance as to accuracy.

It was felt that some of the inconsistencies in the laboratory results were due to experimental technique. A better procedure for cleaning the cores and establishing a connate water saturation should be investigated. Such concepts as changing the direction of flow and using vertical flow may be employed. Poor laboratory technique may result in a mobile connate water saturation and/or a change in wettability of the porous medium during a series of tests. A method of alternately flooding the core with water and with oil to bring about stable equilibrium conditions prior to conducting a waterflood test should be employed. It was believed that this procedure would enable a reliable connate water saturation to be established.

Additional tests should be performed using oil-water viscosity ratios of less than unity to give a more complete knowledge of waterflood behavior. Also, it should be possible to obtain a better understanding of the fingering phenomena and to determine if fingering actually occurs at these conditions.

A brine should be used as the displacing phase in waterfloods rather than distilled water. It was suggested that distilled water may decrease the permeability of some systems.

The concept of improving the oil displacement efficiency by wettability adjustment should be examined more thoroughly. It was suggested that a system of neutral wettability would yield higher oil recoveries than a strongly water wet system.

NOMENCLATURE

f_w - fraction of water flowing at any point

μ_o - oil viscosity (cp)

μ_w - water viscosity (cp)

q_t - total flow rate (cc/sec)

x - length (cm)

k_o, k_w - relative permeabilities to oil and water respectively (md)

K_{ro}, K_{rw} - relative permeabilities to oil and water respectively, dimensionless function of saturation (fraction)

K_o - effective permeability to oil (darcies)

K - absolute permeability (darcies)

t - time (sec)

ϕ - porosity

A - cross sectional area (cm^2)

S_w - water saturation (fraction)

S_{cw} - connate water saturation (fraction)

V - total flow rate per unit cross sectional area (cm/sec)

V_o - oil flow rate per unit cross sectional area (cm/sec)

V_w - water flow rate per unit cross sectional area (cm/sec)

NOMENCLATURE (CONTINUED)

P_c - capillary pressure (atm)

P_o - pressure in oil phase (atm)

P_w - pressure in water phase (atm)

L - length of flooded system (cm)

T - $\frac{tV}{\phi L}$ = dimensionless time coordinate

X - $\frac{x}{L}$ = dimensionless space coordinate

M - μ_o/μ_w = oil water viscosity ratio

F - $(1 + \frac{k_o}{C\,k_w})^{-1}$ function of relative permeabilities and viscosity ratio

$LV\mu_w$ - scaling coefficient $(\frac{cm^2 cp}{min})$

ΔP - differential pressure (psig)

PV - pore volume (percent)

IOIP - initial oil in place (percent)

σ - surface tension (dynes/cm)

WOR - water-oil ratio

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APPENDIX A

TABLE 1-A

Series A Waterflood:

Summary of Oil Recoveries in Limestone Core for Various Water Injection Rates.

Water-Wet System M = 1.5 S_{cw} = 40.5%

Test No.	Injection Rate cc/hr.	$LV\mu_w$ $\frac{cm^2 cp}{min}$	Oil Recovery to Water Breakthrough % IOIP	Oil Recovery to WOR = 20:1 % IOIP
1	10	0.045	35.2	43.2
2	50	0.229	30.3	45.8
3	160	0.726	18.3	46.6
4	320	1.451	16.8	45.7
5	480	2.177	14.1	45.7

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TABLE 2-A

Series B Waterflood:

Summary of Oil Recoveries in Limestone Core for Various Water Injection Rates.

Water-Wet System M = 4.38 S_{cw} = 40.5%

Test No.	Injection Rate cc/hr.	$LV\mu_w$ $\frac{cm^2 cp}{min}$	Oil Recovery to Water Breakthrough % IOIP	Oil Recovery to WOR = 20:1 % IOIP
1	2.5	0.0113	14.8	65
2	20	0.091	13.3	58
3	60	0.272	16.4	62
4	120	0.544	12.7	65
5	200	0.908	10.7	64

TABLE 3-A

Series C Waterflood:

Summary of Oil Recoveries in Unconsolidated Sand Pack for Various Water Injection Rates.

Water-Wet System $M = 1.5$ $S_{cs} = 21.8\%$

Test No.	Injection Rate cc/hr.	$LV\mu_w$ $\frac{cm^2 cp}{min}$	Oil Recovery to Water Breakthrough % IOIP	Oil Recovery to WOR = 20:1 % IOIP
1	10	0.268	52.8	60.6
2	40	1.074	49.8	62.5
3	100	2.68	52.3	61.5
4	200	5.37	55.0	61.8
5	320	8.59	55.3	61.9
6	560	15.03	52.6	60.3
7	840	22.54	46.3	59.6

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TABLE 4-A

Series D Waterflood:

Summary of Oil Recoveries in Alundum Al Core for Various Water Injection Rates.

Water-Wet System $M = 1.82$ $S_{cw} = 15.46\%$

Test No.	Injection Rate cc/hr.	$LV\mu_w$ $\frac{cm^2 cp}{min}$	Oil Recovery to Water Breakthrough % IOIP	Oil Recovery to WOR = 20:1 % IOIP
1	10	1.0	63.55	63.84
2	20	2.0	61.80	62.39
3	40	4.01	58.01	60.05
4	60	6.01	51.76	60.15
5	100	10.01	46.40	58.44
6	160	16.01	42.94	56.76
7	240	24.01	48.53	57.94
8	320	32.01	47.28	57.30
9	400	40.02	34.40	52.48

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TABLE 5-A

Series E Waterflood:

Summary of Oil Recoveries in Alundum Al Core for Various Water Injection Rates.

Water-Wet System M = 1.82 S_{cw} = 14.19%

Test No.	Injection Rate cc/hr.	$LV\mu_w$ $\frac{cm^2 cp}{min}$	Oil Recovery to Water Breakthrough % IOIP	Oil Recovery to WOR = 20:1 % IOIP
1	100	10.0	49.27	57.34
2	160	16.01	48.12	57.93
3	240	24.01	53.89	57.64
4	320	32.01	54.73	57.88

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TABLE 6-A

Series F Waterflood:

Summary of Oil Recoveries in Alundum Al Core for Various Water Injection Rates.

Water-Wet System M = 1.82 S_{cw} = 12.6%

Test No.	Injection Rate cc/hr.	$LV\mu_w$ $\frac{cm^2 cp}{min}$	Oil Recovery to Water Breakthrough % IOIP	Oil Recovery to WOR = 20:1 % IOIP
1	100	10.0	59.94	59.94
2	160	16.01	57.79	60.62
3	240	24.01	57.71	58.64
4	320	32.01	57.22	58.64

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TABLE 7-A

Series G Waterflood:

Summary of Oil Recoveries in Alundum Al Core for Various Water Injection Rates.

Water-Wet System M = 1.82 S_{cw} = 0%

Test No.	Injection Rate cc/hr.	$LV\mu_w$ $\frac{cm^2 cp}{min}$	Oil Recovery to Water Breakthrough % IOIP	Oil Recovery to WOR = 20:1 % IOIP
1	10	1.0	71.61	72.84
2	40	4.0	68.8	69.6
3	120	12.01	66.0	66.2
4	240	24.01	67.5	67.92
5	320	32.01	65.42	66.46
6	480	48.02	65.23	66.04

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TABLE 8-A

Series H Waterflood:

Summary of Oil Recoveries in Alundum Core A2 for Various Water Injection Rates.

Water-Wet System M = 6.61 S_{cw} = 22.1%

Test No.	Injection Rate cc/hr.	$LV\mu_w$ $\frac{cm^2 cp}{min}$	Oil Recovery to Water Breakthrough % IOIP	Oil Recovery to WOR = 20:1 % IOIP
1	40	5.4	48.31	63.02
2	80	10.8	41.65	59.17
3	120	16.2	36.28	55.25
4	200	27.0	38.14	55.05
5	320	43.2	35.25	42.6

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TABLE 9-A

Series J Waterflood:

Summary of Oil Recoveries in Alundum Core A2 for Various Water Injection Rates.

Oil-Wet System $M = 6.61$ $S_{cw} = 22.4\%$

Test No.	Injection Rate cc/hr	$LV\mu_w$ $\frac{cm^2 cp}{min}$	Oil Recovery to Water Breakthrough % IOIP	Oil Recovery to WOR = 20:1 % IOIP
1	40	5.4	42.53	53.53
2	80	10.8	39.5	49.79
3	120	16.2	38.87	47.90
4	200	27.0	38.59	47.71
5	320	43.2	34.64	43.56

TABLE 10-A

Leverett's J-Function:

Calculation of the Constant for the Alundum Al Core

$$J = \frac{Pc}{\sigma} \left(\frac{K}{\phi}\right)^{\frac{1}{2}}$$ K, ϕ, σ are constant

$$K = 378 \text{ md (see Table 1)}$$

$$= \frac{378}{1.013 \times 10^{11}}$$

$$= 372 \times 10^{-11} \quad cm^2$$

$$\phi = 0.236$$

$$\sigma_{Hg} = 480 \quad dynes/cm$$

$$Pc = dynes/cm^2$$

$$\therefore \quad J = \frac{Pc}{480} \left(\frac{372 \times 10^{-11}}{0.236}\right)^{\frac{1}{2}}$$

$$= (2.615 \times 10^{-7}) \quad Pc$$

TABLE 11-A

Converting Capillary Pressure Data* into the J-Function

(1)	(2)	(3)	(4)
Capillary Pressure		Saturation of Wetting Phase	
PSIA	Dynes/ $cm^2 \times 10^4$	%	J-Function (2) x 2.615 x 10^{-7}
13.6	93.8	97.6	0.245
16.6	114.5	61	0.299
20.6	163	36	0.426
35.6	245.2	22	0.642
54.6	376	17	0.984
75.6	522	16	1.365
113.6	784	15.4	2.05
207.6	1430	14.8	3.74
528.6	3640	14	9.52

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* Capillary Pressure data obtained by employing the Mercury Injection Method.

TABLE 12-A

Calculation of Water-Oil Relative Permeability Ratios by Unsteady State Method

Waterflood D, Test 2, for Alundum Al Core

(1) Measurement No.	(2) Inst. Oil Production cc	(3) Inst. Water Production cc	(4) (2) + (3)	(5) $\frac{1}{2}$ (4)	(6) Cum. Oil Production $=\Sigma(2)$ cc	(7) Cum. Water Production $=\Sigma(3)$ cc	(8) Inst. WOR (3)/(2)
1	17.6	0	17.6	8.8	17.6	0	0
2	0.4	0.6	1.0	0.5	18.0	0.6	1.5
3	0.6	1.0	1.6	0.8	18.6	1.6	1.67
4	0.3	1.6	1.9	0.95	18.9	3.2	5.34
5	0.4	1.5	1.9	0.95	19.3	4.7	3.75
6	0.2	1.9	2.1	1.05	19.5	6.6	9.5
7	0.3	1.7	2.0	1.0	19.8	8.3	5.66
8	0.2	2.4	2.6	1.3	20.0	10.7	12.0
9	0.1	3.0	3.1	1.55	20.1	13.7	30.0
10	0.3	3.9	4.2	2.1	20.4	17.6	13.0
11	0.05	5.0	5.5	2.75	20.45	22.6	100.0

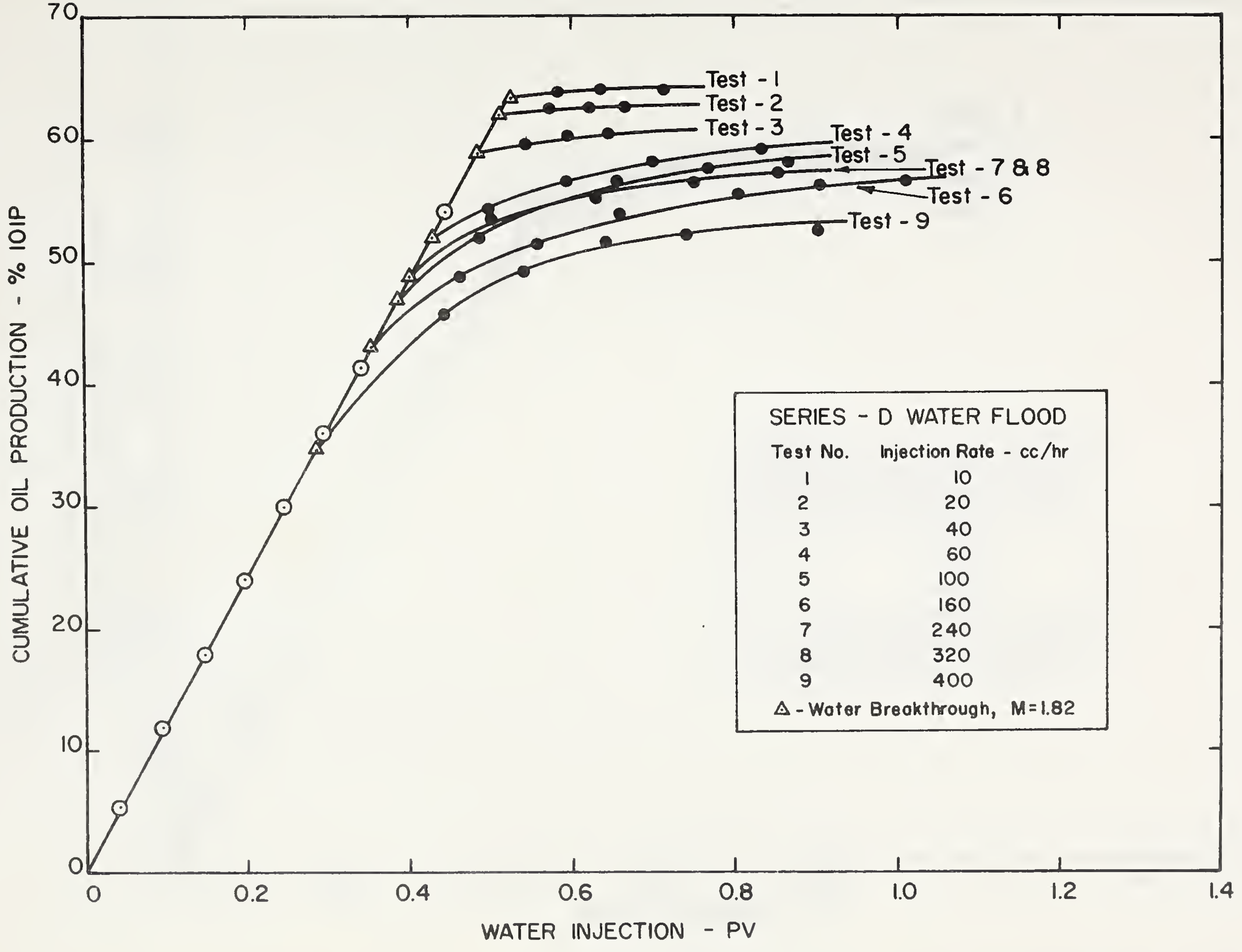
TABLE 12-A (Cont'd)

(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
1 ÷ WOR= 1 + (8)	f_o= 1/(9) fract.	$(1-f_o)/f_o$ = (1 − (10))/(10)	k_w/k_o = (11) x μ_w/μ_o	$\frac{1}{2}$ (2)	(6) − (13)/PV	S_{wA} = (14) + S_{cw} frac. PV	Total Prod. = (6) + (7) cc
1.0	1.0	0	0	8.8	.217	.3775	17.6
2.5	0.4	1.5	0.825	0.2	.439	.5995	18.6
2.67	0.375	1.67	0.917	0.3	.452	.6125	20.2
6.34	0.158	5.33	2.93	0.15	.463	.6235	22.1
4.75	0.211	3.75	2.063	0.2	.472	.6325	24.0
10.5	0.095	9.53	5.24	0.1	.479	.6395	26.1
6.66	0.15	5.67	3.12	0.15	.485	.6455	28.1
13.0	0.077	12.0	6.6	0.1	.492	.6525	30.7
31.0	0.032	30.2	16.6	0.05	.496	.6565	33.8
14.0	0.072	12.9	7.1	0.15	.501	.6615	38.0
101.0	0.01	99.0	54.5	0.025	.504	.6645	43.05

TABLE 12-A (Cont'd)

(17) (16) - (5)	(18) (17) / PV	(19) (10) x (18)	(20) S_{wd} (15) - (19) frac.	(21) S_{wd} (20) x 100 %
8.8	.217	.217	.1605	16.05
18.1	.447	.179	.4205	42.05
19.4	.479	.1794	.4331	43.31
21.15	.522	.0825	.5410	54.10
23.05	.570	.1202	.5123	51.23
25.05	.618	.0587	.5808	58.08
27.1	.668	.1002	.5453	54.53
29.4	.726	.0558	.5967	59.67
32.25	.796	.0255	.6310	63.10
35.9	.887	.0639	.5976	59.76
40.3	.994	.0099	.6546	65.46

APPENDIX B



SERIES - D WATER FLOOD

Test No.	Injection Rate - cc/hr
1	10
2	20
3	40
4	60
5	100
6	160
7	240
8	320
9	400

△ - Water Breakthrough, M=1.82

FIG. 1-B. RELATION BETWEEN CUMULATIVE OIL PRODUCTION AND WATER INJECTED.

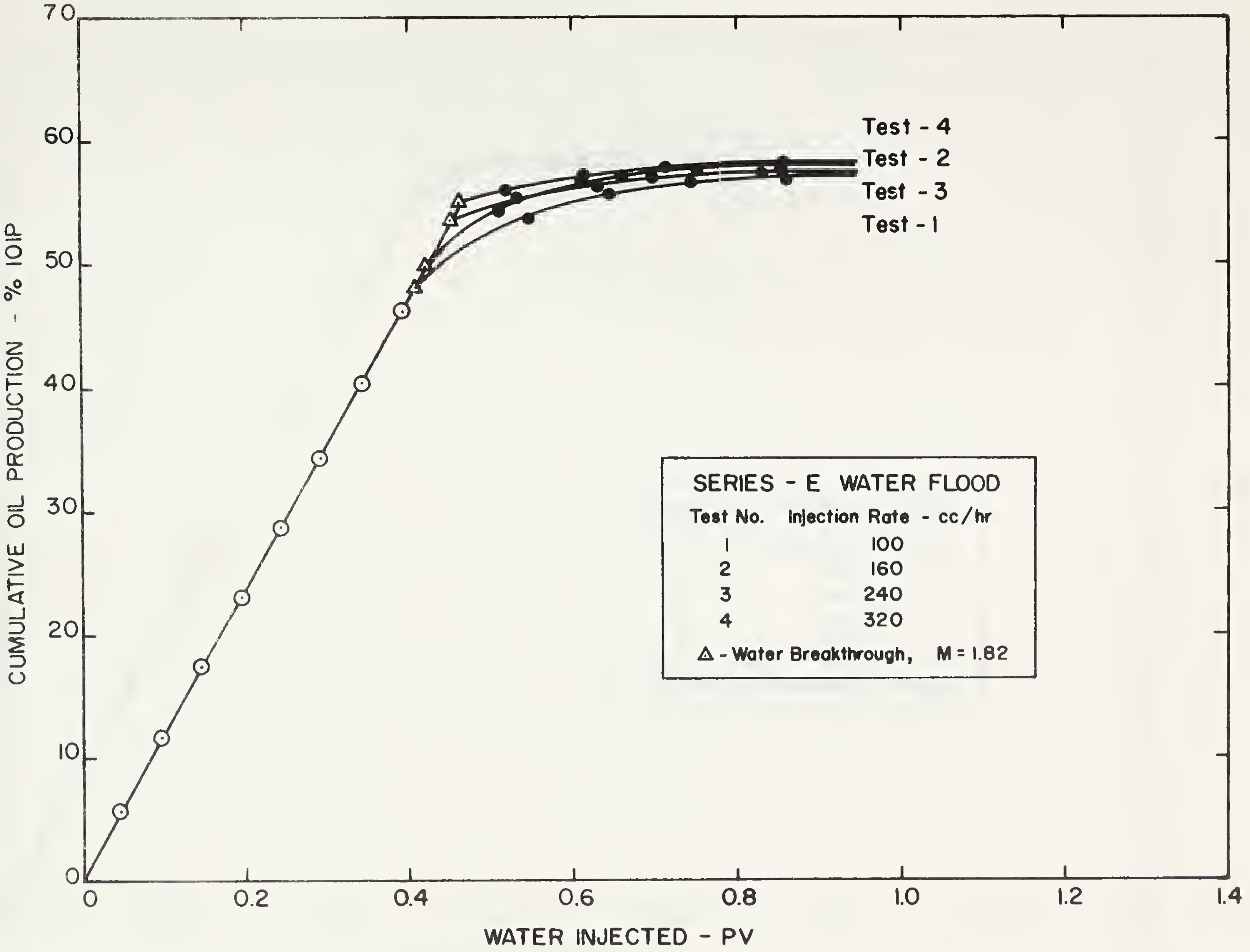


FIG. 2-B. RELATION BETWEEN CUMULATIVE OIL PRODUCTION AND WATER INJECTED.

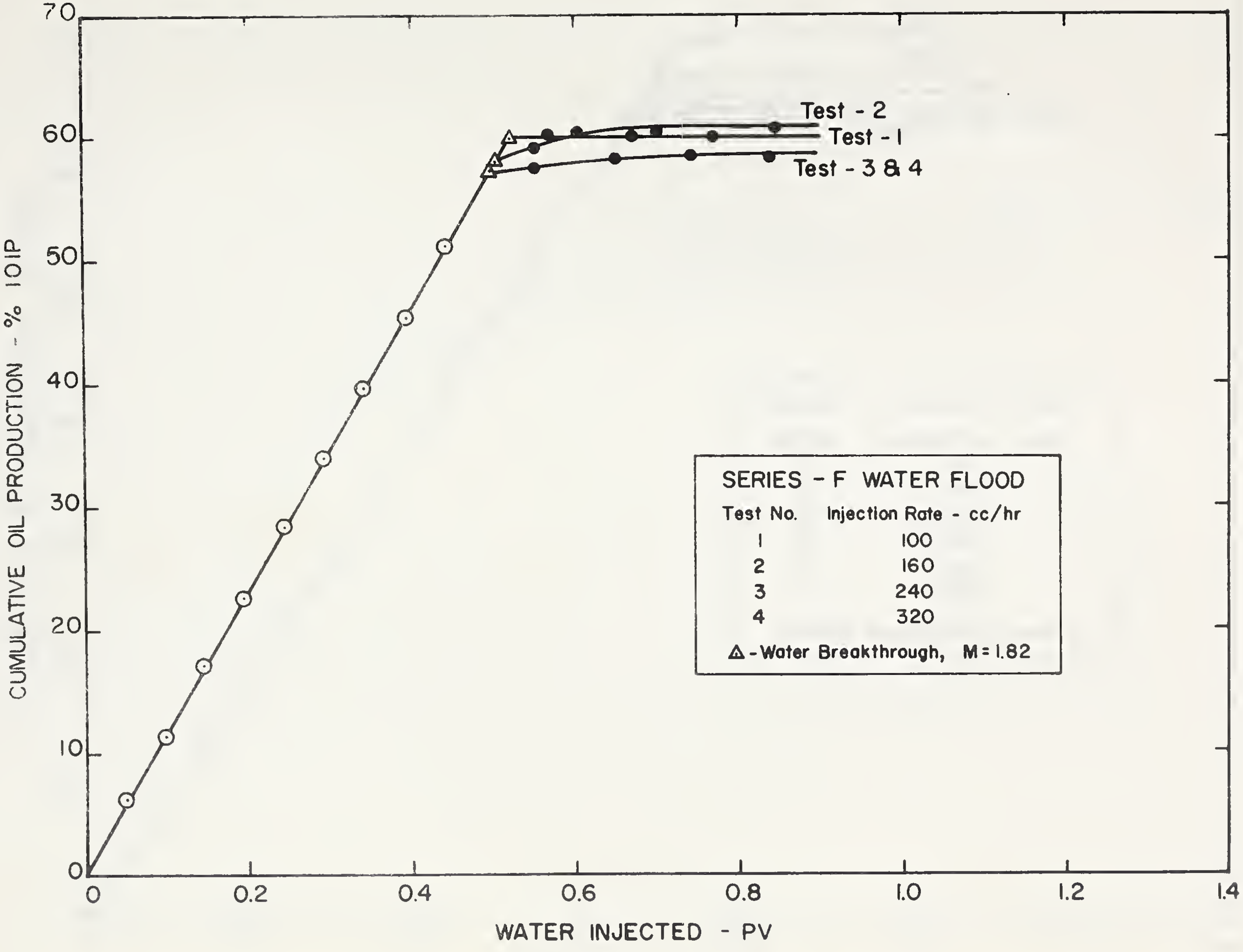


FIG. 3-B. RELATION BETWEEN CUMULATIVE OIL PRODUCTION AND WATER INJECTED.

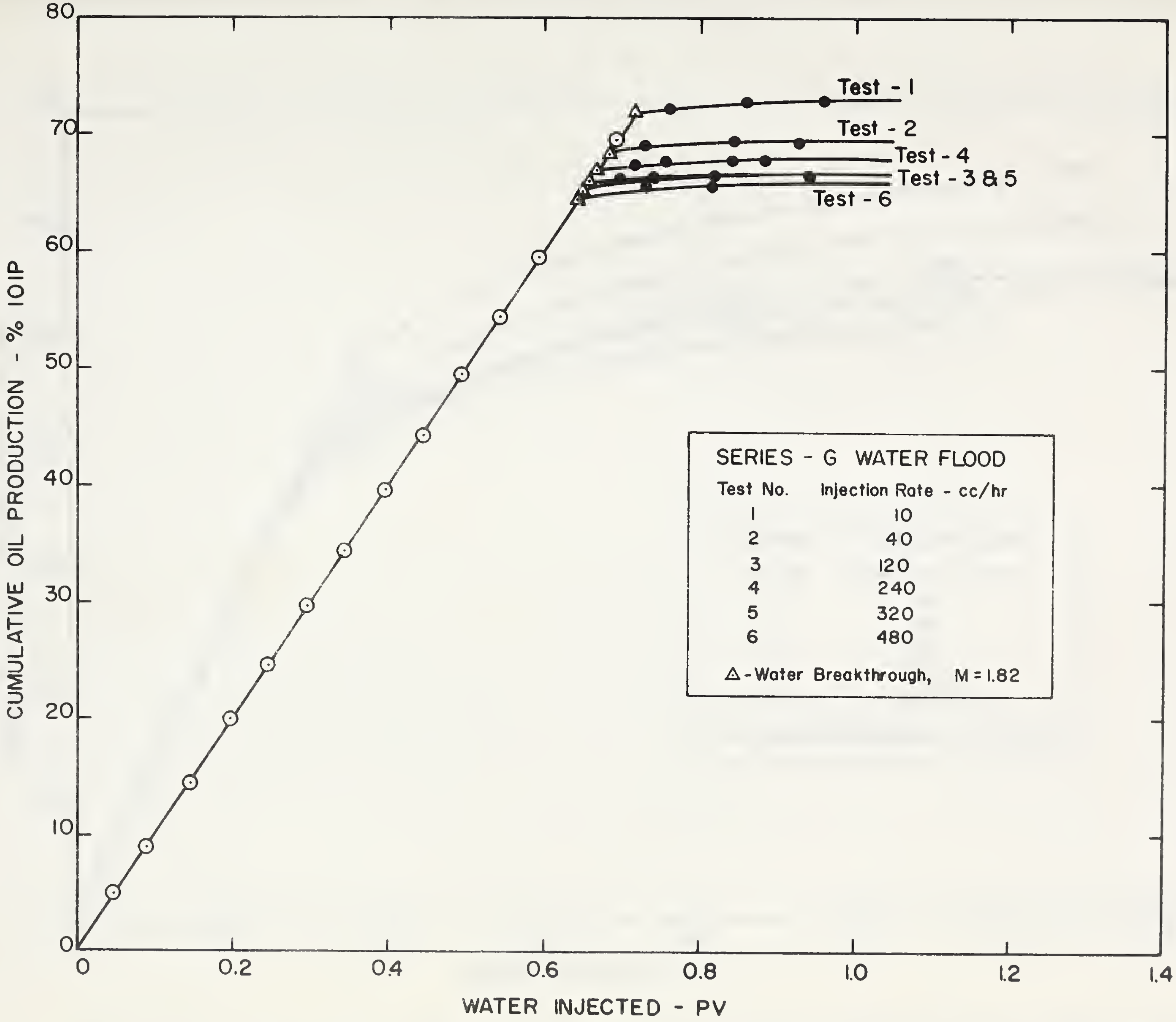


FIG. 4-B. RELATION BETWEEN CUMULATIVE OIL PRODUCTION AND WATER INJECTED.

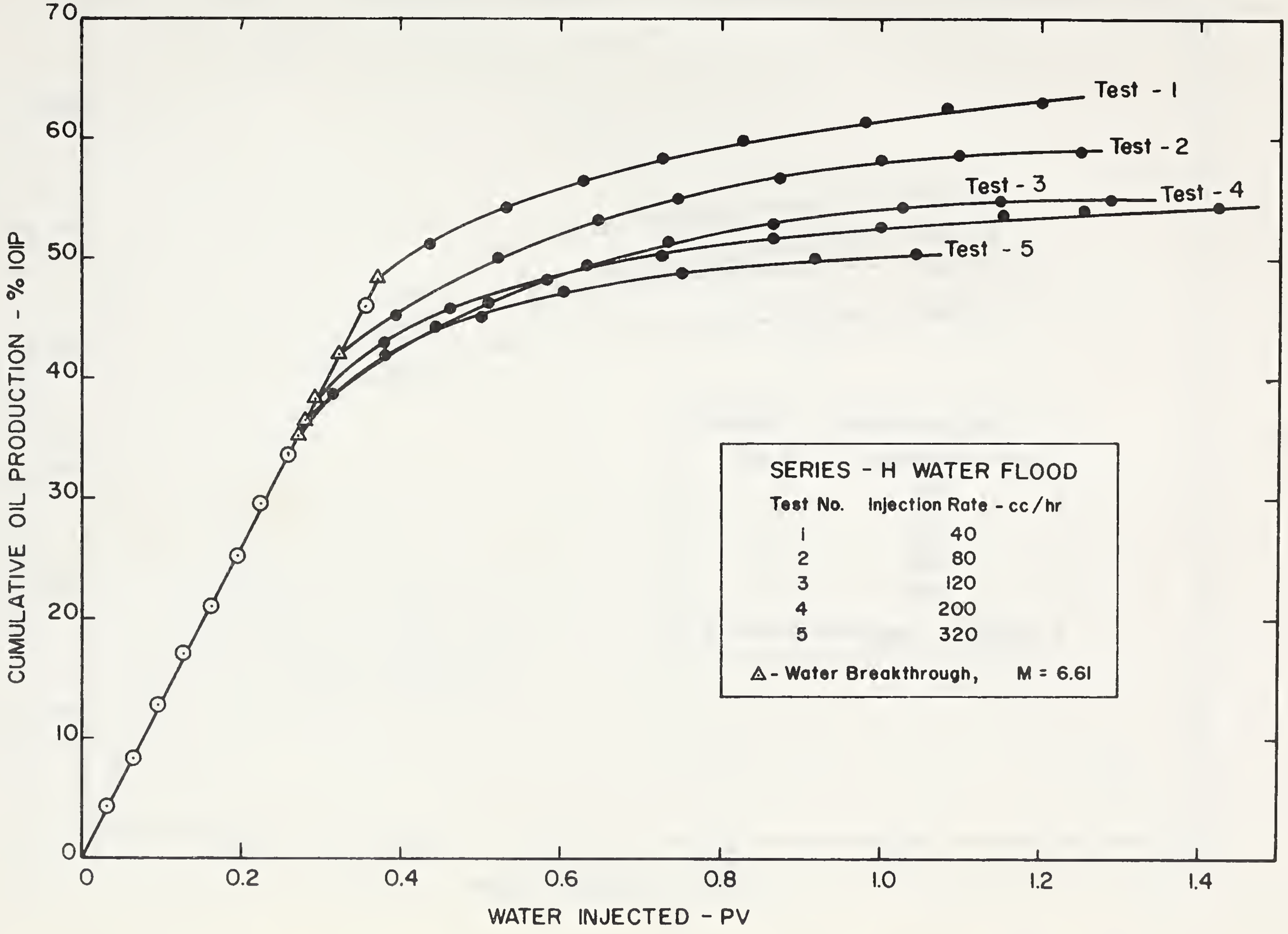


FIG. 5-B. RELATION BETWEEN CUMULATIVE OIL PRODUCTION AND WATER INJECTED.

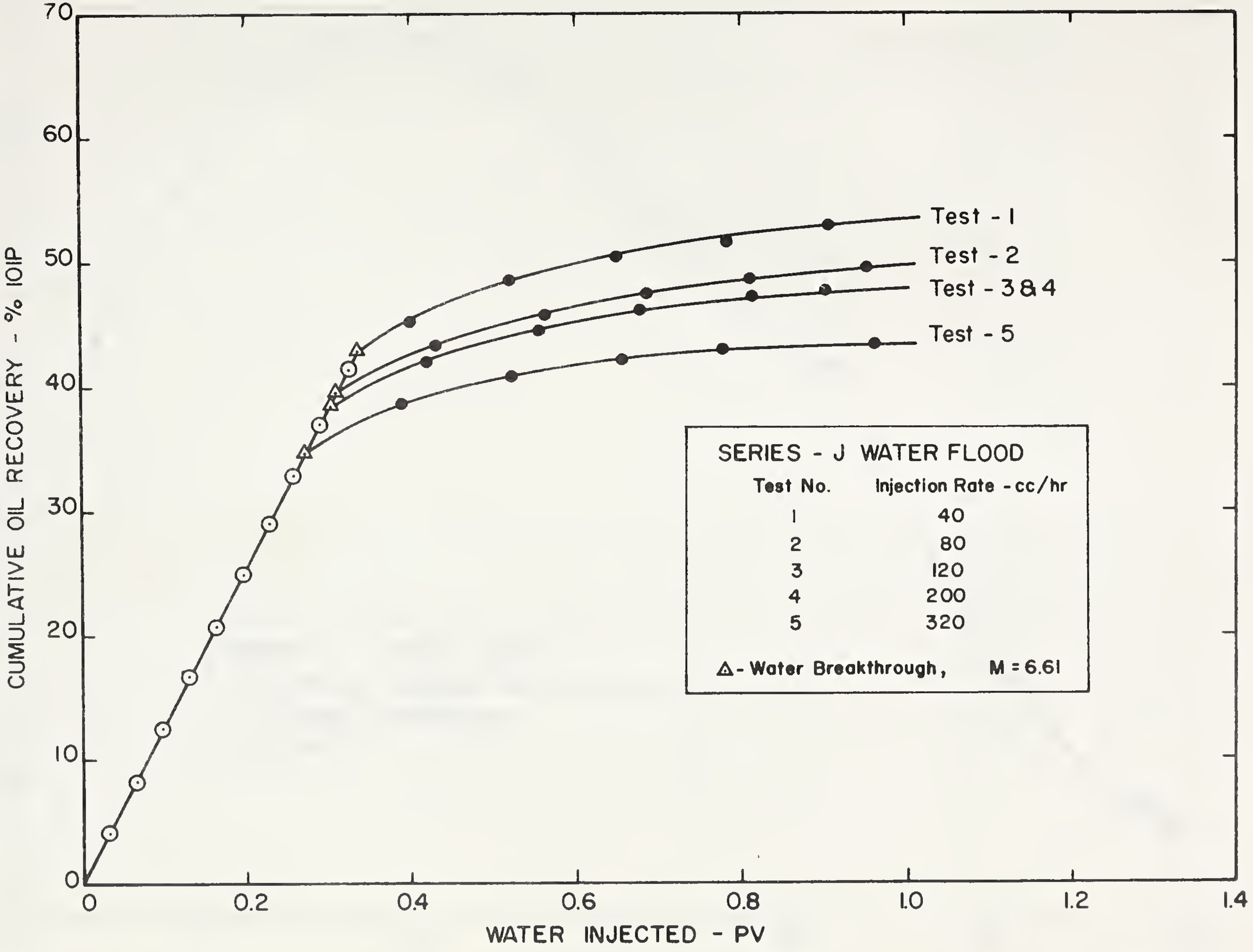


FIG. 6-B. RELATION BETWEEN CUMULATIVE OIL PRODUCTION AND WATER INJECTED.

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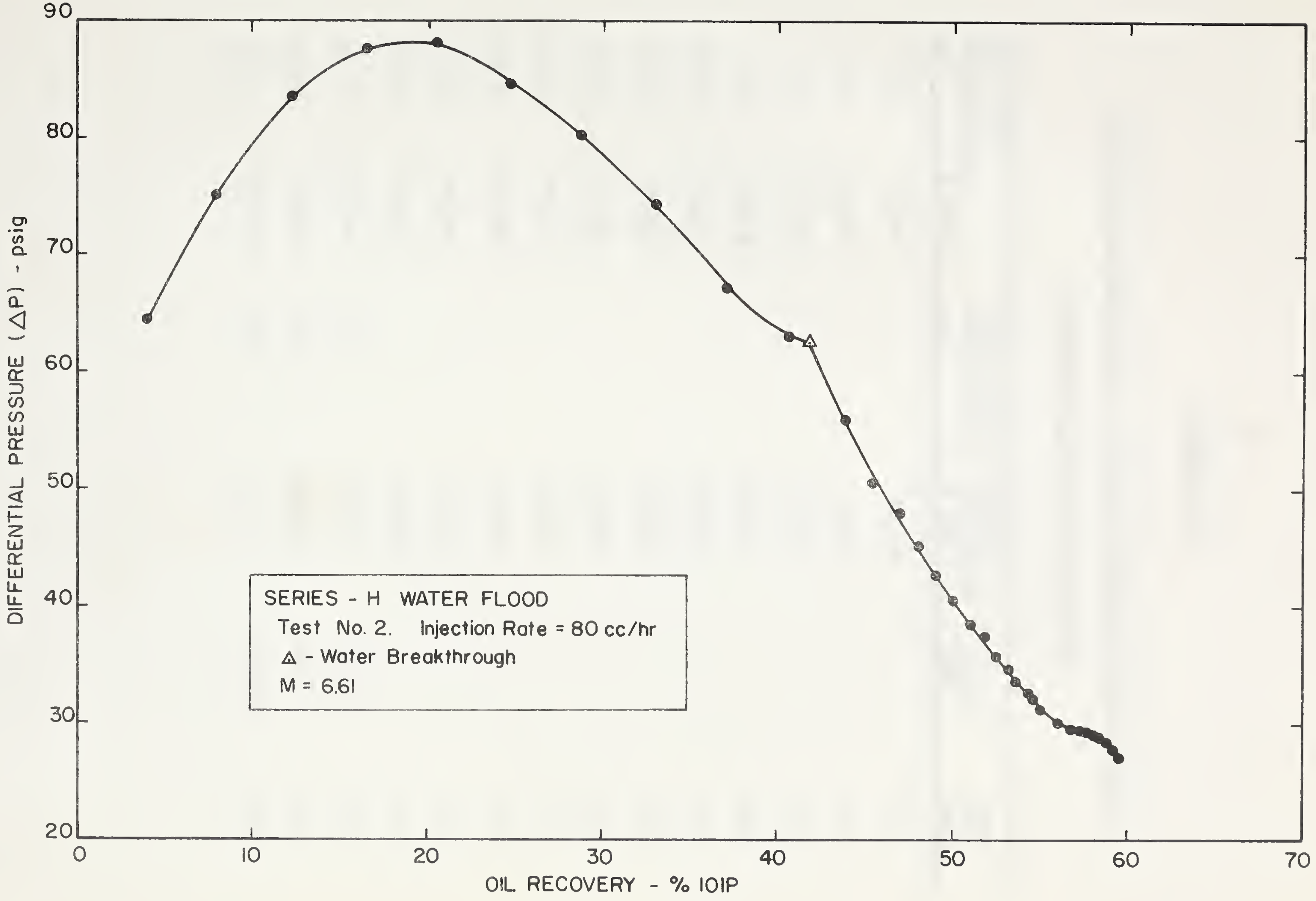

FIG. 7-B. DIFFERENTIAL PRESSURE versus OIL RECOVERY.

TABLE 1-B

Production History: Series D Waterflood, Test 1

Injection Rate = 10 cc/hr.

Cum. Oil Production cc	Cum. Oil Production %IOIP	Cum. Water Production cc	Water Injected % PV	Inst. WOR	ΔP PSIG
2.0	5.83		4.94		6.7
4.0	11.66		9.88		6.5
6.0	17.49		14.81		5.5
8.0	23.32		19.75		5.2
10.0	29.15		24.69		5.0
12.0	34.99		29.63		4.8
14.0	40.81		34.57		4.7
16.0	46.64		39.51		4.7
18.0	52.97		44.44		4.7
20.0	58.30		49.38		4.7
21.8	63.55		53.82		4.7
21.9	63.84	1.9	58.7	19:1	4.7
21.9	63.84	3.9	63.7	∞	4.7
21.9	63.84	6.9	71.3	∞	4.7

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TABLE 2-B

Production History: Series D Waterflood, Test 2

Injection Rate = 20 cc/hr.

Cum. Oil Production cc	% IOIP	Cum. Water Production cc	Water Injected % PV	Inst. WOR	ΔP PSIG
2.0	5.83		4.94		10.7
4.0	11.66		9.88		9.0
6.0	17.49		14.81		8.5
8.0	23.32		19.75		8.3
10.0	29.15		24.69		8.3
12.0	34.99		29.63		8.3
14.0	40.81		34.57		8.4
16.0	46.64		39.51		8.5
18.0	52.47		44.44		8.5
20.0	58.30		49.38		8.5
21.2	61.80		52.34		8.3
21.4	62.39	1.8	57.3	9:1	8.3
21.4	62.39	3.8	62.2	∞	8.2
21.4	62.39	5.6	66.6	∞	8.2

TABLE 3-B

Production History: Series D Waterflood, Test 3

Injection Rate = 40 cc/hr.

Cum. Oil Production cc	% IOIP	Cum. Water Production cc	Water Injected % PV	Inst. WOR	ΔP PSIG
2.0	5.83		4.94		17.2
4.0	11.66		9.88		17.0
6.0	17.49		14.81		16.3
8.0	23.32		19.75		16.2
10.0	29.15		24.69		16.1
12.0	34.99		29.63		16.0
14.0	40.81		34.57		16.0
16.0	46.64		39.51		15.8
18.0	52.47		44.44		15.8
19.9	58.01		49.13		15.7
20.4	59.47	1.5	54.2	3:1	15.6
20.6	60.05	3.3	59.1	9:1	15.6
20.6	60.05	5.4	64.2	∞	15.6

TABLE 4-B

Production History: Series D Waterflood, Test 4

Injection Rate = 60 cc/hr.

Cum. Oil Production cc	% IOIP	Cum. Water Production cc	Water Injected % PV	Inst. WOR	ΔP PSIG
2.0	5.88		4.94		39.5
4.0	11.76		9.88		38.5
6.0	17.65		14.81		37.0
8.0	23.53		19.75		35.4
10.0	29.41		24.69		33.4
12.0	35.29		29.63		31.5
14.0	41.18		34.57		29.3
16.0	47.06		39.51		27.5
17.6	51.76		43.46		26.2
18.0	52.94	0.6	45.9	1.5:1	25.2
18.6	54.71	1.6	49.8	1.67:1	24.0
18.9	55.59	3.2	54.6	5.34:1	22.7
19.3	56.76	4.7	59.2	3.75:1	21.7
19.5	57.35	6.6	64.4	9.5 :1	20.8
19.8	58.24	8.3	69.4	5.66:1	20.2
20.0	58.8	10.7	75.7	12.00:1	19.5
20.1	59.12	13.7	83.5	30.00:1	18.7
20.4	60.0	17.6	93.7	13.3 :1	18.2
20.45	60.15	22.6	107.0	100.00:1	18.0
20.45	60.15	25.8	114.0	∞	18.0

TABLE 5-B

Production History: Series D Waterflood, Test 5

Injection Rate = 100 cc/hr

Cum. Oil Production cc	% IOIP	Cum. Water Production cc	Water Injected % PV	Inst. WOR	ΔP PSIG
2.0	5.87		4.94		65.0
4.0	11.75		9.88		77.0
6.0	17.62		14.81		83.5
8.0	23.49		19.75		86.7
10.0	29.37		24.69		85.7
12.0	35.24		29.63		81.7
14.0	41.12		34.57		78.0
15.8	46.40		39.01		75.0
17.0	49.93	0.8	43.9	0.67:1	69.5
17.4	51.10	1.4	46.4	1.5 :1	66.0
17.8	52.28	2.0	48.8	1.5 :1	62.0
18.6	54.63	3.2	53.8	1.5 :1	58.0
19.2	56.39	5.6	61.3	4.00:1	52.2
19.4	56.98	7.6	66.6	10.00:1	49.0
19.7	57.86	11.3	76.5	12.3 :1	44.2
19.8	58.15	13.2	81.4	19.00:1	41.2
19.9	58.44	15.1	86.4	19.00:1	40.5
19.9	58.44	16.1	89.0	∞	40.5

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TABLE 6-B

Production History: Series D Waterflood, Test 6

Injection Rate = 160 cc/hr

Cum. Oil Production cc	% IOIP	Cum. Water Production cc	Water Injected % PV	Inst. WOR	ΔP PSIG
2.0	5.88		4.94		62.5
4.0	11.76		9.88		72.5
6.0	17.65		14.81		79.0
8.0	23.53		19.75		83.0
10.0	29.41		24.69		83.5
12.0	35.29		29.63		82.7
14.0	41.18		34.57		81.0
14.6	42.94		36.05		80.0
15.8	46.47	0.8	41.0	0.67:1	77.0
16.6	48.82	2.0	45.8	1.5 :1	74.0
17.1	50.29	3.5	50.8	3.00:1	71.0
17.6	51.76	5.0	55.8	3.00:1	69.0
18.0	52.94	6.6	60.7	4.00:1	67.0
18.4	54.12	8.2	65.7	4.00:1	64.0
18.8	55.29	11.8	75.5	9.00:1	60.7
19.0	55.88	13.6	80.5	9.00:1	58.7
19.2	56.47	15.8	85.4	11.00:1	57.7
19.25	56.62	17.75	91.3	39.00:1	56.5
19.3	56.76	19.7	96.2	39.00:1	55.7
19.3	56.76	21.7	101.1	∞	55.7

TABLE 7-B

Production History: Series D Waterflood, Test 7

Injection Rate = 240 cc/hr

Cum. Oil Production cc	% IOIP	Cum. Water Production cc	Water Injected % PV	Inst. WOR	ΔP PSIG
2.0	5.88		4.94		64.0
4.0	11.76		9.88		71.0
6.0	17.65		14.81		76.0
8.0	23.53		19.75		79.0
10.0	29.41		24.69		82.0
12.0	35.29		29.63		84.0
14.0	41.18		34.57		85.2
16.0	47.06		39.51		85.2
16.5	48.53		40.74		84.0
18.3	53.82	2.0	50.2	1.11:1	83.2
18.7	55.0	7.0	63.4	12.5 :1	81.2
18.7	55.0	7.8	65.4	∞	79.0
19.5	57.35	11.0	75.3	3.76:1	77.5
19.7	57.94	12.8	80.3	9.00:1	76.5
19.7	57.94	14.8	85.2	∞	76.0

TABLE 8-B

Production History: Series D Waterflood, Test 8

Injection Rate = 320 cc/hr

Cum. Oil Production cc	% IOIP	Cum. Water Production cc	Water Injected % PV	Inst. WOR	ΔP PSIG
2.0	5.73		4.94		140.0
4.0	11.46		9.88		160.0
6.0	17.19		14.81		170.0
8.0	22.92		19.75		173.0
10.0	28.65		24.69		169.0
12.0	34.38		29.63		165.0
14.0	40.11		34.57		157.0
16.0	45.85		39.51		150.0
16.5	47.28		40.74		144.0
18.3	52.44	0.2	45.7	0.11:1	138.0
19.2	55.01	1.3	50.6	1.22:1	132.0
19.8	56.73	2.7	55.6	2.34:1	126.0
19.9	57.02	4.6	60.5	19.00:1	123.0
20.0	57.30	5.5	63.0	9.00:1	118.0
20.0	57.30	8.5	70.4	∞	116.0

TABLE 9-B

Production History: Series D Waterflood, Test 9

Injection Rate = 400 cc/hr

Cum. Oil Production cc	% IOIP	Cum. Water Production cc	Water Injected % PV	Inst. WOR	ΔP PSIG
2.0	5.83		4.94		100.0
4.0	11.66		9.88		120.0
6.0	17.49		14.81		132.0
8.0	23.32		19.75		141.0
10.0	29.15		24.69		147.0
11.8	34.40		29.14		148.0
16.0	46.64	2.0	44.4	0.48:1	143.0
17.0	49.56	5.0	54.3	3.00:1	136.0
17.8	51.90	8.2	64.2	4.00:1	132.0
18.0	52.48	12.0	74.1	19.00:1	128.0
18.0	52.48	16.0	84.0	∞	125.0
18.0	52.48	19.0	91.3	∞	124.0

Table 10-B

Production History: Series E Waterflood, Test 1

Injection Rate = 100 cc/hr

Cum. Oil Production cc	% IOIP	Cum. Water Production cc	Water Injected % PV	Inst. WOR	ΔP PSIG
2.0	5.76		4.94		36.0
4.0	11.53		9.88		39.0
6.0	17.29		14.81		40.5
8.0	23.05		19.75		41.5
10.0	28.81		24.69		42.0
12.0	34.58		29.63		42.0
14.0	40.34		34.57		41.7
16.0	46.10		39.51		41.7
17.1	49.27		42.22		41.2
18.4	53.02	1.7	49.7	1.3 :1	40.7
18.7	53.89	3.4	54.6	5.67:1	39.5
19.0	54.75	5.1	59.6	5.67:1	39.0
19.4	55.90	6.7	64.5	4.00:1	38.5
19.6	56.48	8.5	69.4	9.00:1	38.2
19.8	57.06	10.3	74.3	9.00:1	37.7
19.9	57.34	12.2	79.3	19.00:1	37.2
19.9	57.34	15.2	86.6	∞	37.2

TABLE 11-B

Production History: Series E Waterflood, Test 2

Injection Rate = 160 cc/hr

Cum. Oil Production cc	% IOIP	Cum. Water Production cc	Water Injected % PV	Inst. WOR	ΔP PSIG
2.0	5.76		4.94		63.0
4.0	11.53		9.88		74.7
6.0	17.29		14.81		83.7
8.0	23.05		19.75		86.0
10.0	28.81		24.69		85.2
12.0	34.58		29.63		83.5
14.0	40.34		34.57		80.2
16.0	46.10		39.51		78.2
16.7	48.12		41.23		75.5
18.9	54.47	1.8	51.2	0.82:1	72.2
19.5	56.20	3.2	56.1	2.34:1	68.7
19.7	56.70	5.0	61.0	9.00:1	66.5
19.9	57.34	6.8	66.0	9.00:1	65.7
20.0	57.64	10.7	75.8	39.00:1	63.7
20.1	57.93	12.6	80.7	19.00:1	61.5
20.1	57.93	14.6	85.7	∞	59.7

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TABLE 12-B

Production History: Series E Waterflood, Test 3

Injection Rate = 240 cc/hr

Cum. Oil Production		Cum. Water Production cc	Water Injected % PV	Inst. WOR	ΔP PSIG
cc	% IOIP				
2.0	5.76		4.94		70.0
4.0	11.53		9.88		82.0
6.0	17.29		14.81		90.0
8.0	23.45		19.75		91.0
10.0	28.81		24.69		94.0
12.0	34.59		29.63		96.0
14.0	40.34		34.57		98.0
16.0	46.10		39.51		98.5
18.0	51.87		44.44		97.0
18.7	53.89		46.17		96.5
19.3	55.62	3.4	56.1	5.7:1	93.0
19.9	57.34	5.8	63.4	4.0:1	91.0
20.0	57.64	8.7	70.8	29.0:1	90.0
20.0	57.64	13.7	83.2	∞	89.0

TABLE 13-B

Production History: Series E Waterflood, Test 4

Injection Rate = 320 cc/hr

Cum. Oil Production cc	% IOIP	Cum. Water Production cc	Water Injected % PV	Inst. WOR	ΔP PSIG
2.0	5.73		4.94		95.2
4.0	11.46		9.88		101.0
6.0	17.19		14.81		103.5
8.0	22.92		19.75		105.0
10.0	28.65		24.69		106.0
12.0	34.38		29.63		108.0
14.0	40.11		34.57		109.5
16.0	45.85		39.51		110.0
18.0	51.58		44.44		109.2
19.1	54.73		47.16		108.0
19.5	55.87	1.6	52.2	4:1	106.0
19.7	56.45	5.4	62.0	19:1	104.5
19.9	57.02	9.2	71.9	19:1	103.0
20.2	57.88	14.9	86.6	19:1	102.0
20.2	57.88	19.9	99.0	∞	101.5

TABLE 14-B

Production History: Series F Waterflood, Test 1

Injection Rate = 100 cc/hr

Cum. Oil Production cc	Cum. Oil Production % IOIP	Cum. Water Production cc	Water Injected % PV	Inst. WOR	ΔP PSIG
2.0	5.60		4.94		32.0
4.0	11.20		9.88		32.0
6.0	16.81		14.81		34.0
8.0	22.41		19.75		35.0
10.0	28.01		24.69		35.0
12.0	33.61		29.63		35.5
14.0	39.22		34.57		35.7
16.0	44.82		39.51		36.5
18.0	50.42		44.44		37.0
20.0	56.02		49.38		37.7
21.4	59.94		52.84		37.7
21.4	59.94	2.0	57.7	∞	37.0
21.4	59.94	6.0	67.7	∞	36.0
21.4	59.94	9.6	76.5	∞	35.5

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TABLE 15-B

Production History: Series F Waterflood, Test 2

Injection Rate = 160 cc/hr

Cum. Oil Production cc	% IOIP	Cum. Water Production cc	Water Injected % PV	Inst. WOR	ΔP PSIG
2.0	5.67		4.94		57.0
4.0	11.33		9.88		55.0
6.0	17.00		14.81		55.0
8.0	22.66		19.75		54.7
10.0	28.33		24.69		55.0
12.0	33.99		29.63		55.0
14.0	39.66		34.57		55.5
16.0	45.33		39.51		56.0
18.0	50.99		44.44		56.5
20.0	56.66		49.38		56.5
20.4	57.79		50.37		56.0
20.8	58.92	1.6	55.3	4:1	55.0
21.2	60.34	3.2	60.3	4:1	54.5
21.3	60.47	7.1	70.2	39:1	54.0
21.4	60.62	9.0	75.6	19:1	53.7
21.4	60.62	13.0	84.9	∞	53.5

TABLE 16-B

Production History: Series F Waterflood, Test 3

Injection Rate = 240 cc/hr

Cum. Oil Production cc	% IOIP	Cum. Water Production cc	Water Injected % PV	Inst. WOR	ΔP PSIG
2.0	5.67		4.94		71.0
4.0	11.33		9.88		76.0
6.0	17.00		14.81		79.0
8.0	22.66		19.75		80.5
10.0	28.33		24.69		81.5
12.0	33.99		29.63		82.5
14.0	39.66		34.57		84.0
16.0	45.33		39.51		84.5
18.0	50.99		44.44		84.0
20.3	57.51		50.12		83.5
20.3	57.51	2.0	55.10	---	82.0
20.5	58.08	7.8	69.80	29:1	80.5
20.6	58.36	9.7	74.80	19:1	80.0
20.7	58.64	13.6	84.70	39:1	79.5
20.7	58.64	17.6	94.50	∞	79.5

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TABLE 17-B

Production History: Series F Waterflood, Test 4

Injection Rate = 320 cc/hr

Cum. Oil Production cc	% IOIP	Cum. Water Production cc	Water Injected % PV	Inst. WOR	ΔP PSIG
2.0	5.67		4.94		88.0
4.0	11.33		9.88		94.0
6.0	17.00		14.81		98.5
8.0	22.66		19.75		100.2
10.0	28.33		24.69		100.7
12.0	33.99		29.63		101.5
14.0	39.66		34.57		102.2
16.0	45.33		39.51		103.5
18.0	50.99		44.44		104.0
20.2	57.22		49.88		103.2
20.3	57.51	1.9	54.80	19:1	100.5
20.4	57.79	3.8	59.70	19:1	99.7
20.4	57.79	5.8	64.70	∞	99.2
20.7	58.64	9.5	74.5	12.3:1	98.2
20.7	58.64	16.3	91.3	∞	97.5

TABLE 18-B

Production History: Series G Waterflood, Test 1

Injection Rate = 10 cc/hr

Cum. Oil Production cc	% IOIP	Cum. Water Production cc	Water Injected % PV	Inst. WOR	ΔP PSIG
2.0	4.94		4.94		6.2
4.0	9.88		9.88		4.7
6.0	14.81		14.81		4.2
8.0	19.75		19.75		4.0
10.0	24.69		24.69		3.7
12.0	29.63		29.63		3.7
14.0	34.57		34.57		3.7
16.0	39.51		39.51		3.7
18.0	44.44		44.44		3.7
20.0	49.38		49.38		3.7
22.0	54.32		54.32		4.0
24.0	59.26		59.26		4.2
26.0	64.19		64.19		4.2
28.0	69.13		69.13		4.5
29.0	71.61		71.61		4.5
29.2	72.10	1.8	76.5	9:1	4.2
29.3	72.35	3.7	81.5	19:1	4.2
29.4	72.59	5.6	86.4	19:1	4.2
29.5	72.84	7.5	91.4	19:1	4.2
29.5	72.84	9.5	96.4	∞	4.2

TABLE 19-B

Production History: Series G Waterflood, Test 2

Injection Rate = 40 cc/hr.

Cum. Oil Production cc	Cum. Oil Production % IOIP	Cum. Water Production cc	Water Injected % PV	Inst. WOR	ΔP PSIG
2.0	4.00		4.0		6.7
4.0	8.00		8.0		6.2
6.0	12.00		12.0		6.0
8.0	16.00		16.0		6.0
10.0	20.00		20.0		5.7
12.0	24.00		24.0		5.7
14.0	28.00		28.0		5.7
16.0	32.00		32.0		5.7
18.0	36.00		36.0		5.7
20.0	40.00		40.0		5.7
22.0	44.00		44.0		5.7
24.0	48.00		48.0		5.7
26.0	52.00		52.0		5.7
28.0	56.00		56.0		6.0
30.0	60.00		60.0		6.2
32.0	64.00		64.0		6.5
34.0	68.00		68.0		6.7
34.4	68.80		68.8		6.7
34.7	69.40	1.8	72.8	6:1	6.5
34.8	69.60	3.6	76.8	18:1	6.2
34.8	69.60	7.6	84.8	∞	6.2

TABLE 20-B

Production History: Series G Waterflood, Test 3

Injection Rate = 120 cc/hr

Cum. Oil Production		Cum. Water Production	Water Injected	Inst.	ΔP
cc	% IOIP	cc	% PV	WOR	PSIG
2.0	4.00		4.0		18.5
4.0	8.00		8.0		17.5
6.0	12.00		12.0		16.5
8.0	16.00		16.0		16.0
10.0	20.00		20.0		15.5
12.0	24.00		24.0		15.5
14.0	28.00		28.0		15.5
16.0	32.00		32.0		15.5
18.0	36.00		36.0		15.5
20.0	40.00		40.0		15.5
22.0	44.00		44.0		15.5
24.0	48.00		48.0		15.2
26.0	52.00		52.0		15.5
28.0	56.00		56.0		15.7
30.0	60.00		60.0		16.0
32.0	64.00		64.0		16.2
33.0	66.00		66.0		16.2
33.1	66.20	1.8	70.0	18:1	16.0
33.2	66.40	3.8	74.0	20:1	16.0
33.2	66.40	5.8	78.0	∞	16.0
33.3	66.60	7.7	82.0	19:1	15.7
33.3	66.60	9.7	86.0	∞	15.7

TABLE 21-B

Production History: Series G Waterflood, Test 4

Injection Rate = 240 cc/hr

Cum. Oil Production cc	% IOIP	Cum. Water Production cc	Water Injected % PV	Inst. WOR	ΔP PSIG
2.0	4.17		4.17		29.2
4.0	8.33		8.33		28.7
6.0	12.50		12.50		28.5
8.0	16.67		16.67		28.2
10.0	20.83		20.83		28.2
12.0	25.00		25.00		28.2
14.0	29.17		29.17		28.2
16.0	33.33		33.33		28.2
18.0	37.50		37.50		28.2
20.0	41.66		41.66		28.2
22.0	45.83		45.83		28.2
24.0	50.00		50.00		28.2
26.0	54.17		54.17		28.5
28.0	58.33		58.33		29.0
30.0	62.50		62.50		29.5
32.0	66.67		66.67		29.7
32.4	67.50		67.50		30.0
32.5	67.71	1.9	71.60	19:1	29.7
32.6	67.92	3.8	75.81	19:1	29.5
32.6	67.92	5.8	79.90	∞	29.5

TABLE 22-B

Production History: Series G Waterflood, Test 5

Injection Rate = 320 cc/hr

Cum. Oil Production cc	% IOIP	Cum. Water Production cc	Water Injected % PV	Inst. WOR	ΔP PSIG
2.0	4.17		4.17		43.7
4.0	8.33		8.33		42.0
6.0	12.50		12.50		41.0
8.0	16.67		16.67		40.7
10.0	20.83		20.83		40.2
12.0	25.00		25.00		40.2
14.0	29.17		29.17		40.2
16.0	33.33		33.33		40.5
18.0	37.50		37.50		40.5
20.0	41.66		41.66		40.7
22.0	45.83		45.83		40.7
24.0	50.00		50.00		41.0
26.0	54.17		54.17		41.5
28.0	58.33		58.33		41.5
30.0	62.50		62.50		42.0
31.4	65.42		65.42		43.5
31.6	65.83	1.8	69.6	9:1	43.0
31.8	66.25	3.6	73.7	9:1	43.0
31.8	66.25	5.6	77.8	∞	42.5
31.9	66.46	7.5	82.0	19:1	42.5
31.9	66.46	9.5	86.2	∞	42.0

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TABLE 23-B

Production History: Series G Waterflood, Test 6

Injection Rate = 480 cc/hr

Cum. Oil Production cc	% IOIP	Cum. Water Production cc	Water Injected % PV	Inst. WOR	ΔP PSIG
2.0	4.17		4.17		58.2
4.0	8.33		8.33		57.7
6.0	12.50		12.50		56.7
8.0	16.67		16.67		56.7
10.0	20.83		20.83		56.7
12.0	25.00		25.00		57.0
14.0	29.17		29.17		57.2
16.0	33.33		33.33		57.7
18.0	37.50		37.50		58.0
20.0	41.65		41.65		58.5
22.0	45.83		45.83		58.2
24.0	50.00		50.00		58.2
26.0	54.17		54.17		59.2
28.0	58.33		58.33		61.5
30.0	62.50		62.50		63.5
31.3	65.23		65.23		64.5
31.4	65.42	1.9	69.31	19:1	64.5
31.5	65.63	3.8	73.50	19:1	64.2
31.6	65.83	5.7	77.72	19:1	64.0
31.7	66.04	7.6	81.80	19:1	64.0
31.7	66.04	9.6	85.90	∞	64.0

TABLE 24-B

Production History: Series H Waterflood, Test 1

Injection Rate = 40 cc/hr

Cum. Oil Production cc	% IOIP	Cum. Water Production cc	Water Injected % PV	Inst. WOR	ΔP PSIG
2.0	4.20		3.22		30.0
4.0	8.40		6.45		29.2
6.0	12.60		9.68		28.2
8.0	16.80		12.90		27.0
10.0	21.00		16.12		26.2
12.0	25.21		19.35		24.5
14.0	29.41		22.58		23.0
16.0	33.61		25.80		21.7
18.0	37.81		29.03		20.2
20.0	42.00		32.24		19.0
22.0	46.21		35.48		18.0
23.0	48.31		37.09		17.2
24.3	51.05	2.7	43.59	2.08:1	15.2
25.3	53.15	5.7	50.00	3.00:1	13.7
26.3	55.25	8.7	56.45	3.00:1	12.5
27.0	56.72	12.0	62.90	4.70:1	11.7
27.7	58.19	15.3	69.35	4.70:1	11.2
28.2	59.24	18.8	75.80	7.00:1	10.7
28.5	59.87	22.5	82.25	12.30:1	10.5
28.9	60.71	26.1	88.70	9.00:1	10.2
29.2	61.34	29.8	95.16	12.30:1	10.0
29.6	62.18	33.4	101.61	9.00:1	10.0
29.8	62.60	37.2	108.06	19.00:1	9.7
30.0	63.02	41.0	114.52	19.00:1	9.7
30.0	63.02	43.0	117.74	∞	9.7

TABLE 25-B

Production History: Series H Waterflood, Test 2

Injection Rate = 80 cc/hr

Cum. Oil Production cc	% IOIP	Cum. Water Production cc	Water Injected % PV	Inst. WOR	ΔP PSIG
2.0	4.12		3.22		64.5
4.0	8.25		6.45		75.0
6.0	12.37		9.68		83.5
8.0	16.50		12.90		87.5
10.0	20.62		16.12		88.0
12.0	24.74		19.35		84.7
14.0	28.86		22.58		80.2
16.0	32.99		25.80		74.2
18.0	37.11		29.03		67.0
20.2	41.65		32.60		62.7
22.0	45.36	2.2	39.05	1.22:1	50.5
23.4	48.24	4.8	45.5	1.85:1	45.0
24.4	50.30	7.8	51.9	3.00:1	40.5
25.2	51.95	11.0	58.4	4.00:1	37.2
25.8	53.19	14.4	64.8	5.67:1	34.7
26.4	54.43	17.8	71.4	5.67:1	32.7
26.7	55.05	21.5	77.8	13.40:1	31.2
27.3	56.28	24.9	84.3	5.67:1	30.0
27.8	57.31	28.4	90.6	7.00:1	29.5
28.1	57.93	32.1	97.0	13.40:1	29.0
28.3	58.35	35.9	103.4	19.00:1	28.0
28.4	58.55	39.8	109.9	39.00:1	27.7
28.6	58.96	43.6	116.2	19.00:1	27.2
28.7	59.17	47.5	122.6	39.00:1	27.0
28.7	59.17	49.5	125.7	∞	27.0

TABLE 26-B

Production History: Series H Waterflood, Test 3

Injection Rate = 120 cc/hr

Cum. Oil Production		Cum. Water Production	Water Injected	Inst.	ΔP
cc	% IOIP	cc	% PV	WOR	PSIG
2.0	4.12		3.22		130.0
4.0	8.25		6.45		147.0
6.0	12.37		9.68		166.5
8.0	16.50		12.90		165.5
10.0	20.62		16.12		157.0
12.0	24.74		19.35		145.0
14.0	28.86		22.58		133.0
16.0	32.99		25.80		120.0
17.6	36.28		28.30		110.0
19.7	40.61	1.9	34.80	0.9:1	95.0
21.0	43.29	4.6	41.2	2.1:1	84.0
22.1	45.56	7.5	47.8	2.6:1	77.0
22.7	46.80	10.9	54.2	5.7:1	71.5
23.6	48.65	14.0	60.6	3.5:1	68.0
24.3	50.10	17.3	67.0	4.7:1	65.0
24.8	51.13	21.8	73.4	9.0:1	63.0
25.2	51.95	24.4	79.8	6.5:1	61.0
25.7	52.98	27.9	86.2	7.0:1	60.0
25.9	53.40	31.7	92.6	19.0:1	59.0
26.2	54.02	35.4	99.0	12.4:1	58.5
26.4	54.43	39.2	105.4	19.0:1	57.5
26.6	54.84	43.0	111.8	19.0:1	57.0
26.7	55.05	46.9	118.2	39.0:1	56.5
26.8	55.25	50.8	125.6	39.0:1	55.5
26.8	55.25	52.8	128.8	∞	55.5

TABLE 27-B

Production History: Series H Waterflood, Test 4

Injection Rate = 200 cc/hr

Cum. Oil Production		Cum. Water Production	Water Injected	Inst.	ΔP
cc	% IOIP	cc	% PV	WOR	PSIG
2.0	4.12		3.22		155.0
4.0	8.25		6.45		209.0
6.0	12.37		9.68		237.0
8.0	16.50		12.90		239.0
10.0	20.62		16.12		231.0
12.0	24.74		19.35		218.5
14.0	28.86		22.58		206.0
16.0	32.99		25.80		192.5
18.5	38.14		29.80		181.0
20.7	42.68	1.8	36.2	0.8:1	162.0
21.7	44.74	4.3	42.6	3.0:1	150.5
22.6	46.59	7.9	49.0	3.5:1	142.0
23.1	47.62	11.4	55.4	7.0:1	136.0
23.6	48.65	14.9	61.8	7.0:1	131.5
24.0	49.48	18.5	68.4	9.0:1	128.0
24.4	50.30	22.1	74.8	9.0:1	125.0
24.9	50.72	25.6	81.3	7.0:1	123.0
25.2	51.95	29.3	87.7	12.3:1	120.5
25.3	52.16	33.2	94.2	39.0:1	119.0
25.6	52.78	36.9	100.6	12.3:1	118.5
25.9	53.40	40.6	107.1	12.3:1	117.5
26.0	53.60	44.5	113.6	39.0:1	116.5
26.2	54.02	48.3	123.0	19.0:1	116.0
26.4	54.43	52.1	129.4	19.0:1	115.5
26.6	54.84	55.9	135.9	19.0:1	115.0
26.7	55.05	57.8	139.1	19.0:1	114.0
26.7	55.05	59.8	142.3	∞	114.0

TABLE 28-B

Production History: Series H Waterflood, Test 5

Injection Rate = 320 cc/hr

Cum. Oil Production cc	Cum. Oil Production % IOIP	Cum. Water Production cc	Water Injected % PV	Inst. WOR	ΔP PSIG
2.0	4.12		3.22		169.0
4.0	8.25		6.45		240.0
6.0	12.37		9.68		---
8.0	16.50		12.90		---
10.0	20.62		16.12		---
12.0	24.74		19.35		---
14.0	28.86		22.58		239.0
16.0	32.99		25.80		229.0
17.1	35.25		27.60		222.0
19.7	40.61	1.4	34.0	0.54:1	203.0
21.1	43.50	4.0	40.4	1.80:1	291.0
22.1	45.56	7.0	46.8	3.00:1	181.5
22.8	47.01	10.3	53.3	4.70:1	175.0
23.1	47.62	14.0	59.7	12.30:1	170.5
23.4	48.24	17.7	66.1	12.30:1	166.5
23.6	48.65	21.5	72.5	19.00:1	162.0
24.0	49.48	25.1	79.0	9.00:1	161.0
24.2	49.89	28.9	85.4	19.00:1	159.0
24.3	50.10	32.8	91.8	39.00:1	157.0
24.5	50.51	36.6	98.3	19.00:1	154.5
24.5	50.51	40.6	104.7	∞	154.0

TABLE 29-B

Production History: Series J Waterflood, Test 1

Injection Rate = 40 cc/hr

Cum. Oil Production cc	% IOIP	Cum. Water Production cc	Water Injected % PV	Inst. WOR	ΔP PSIG
2.0	4.15		3.22		25.7
4.0	8.30		6.45		26.5
6.0	12.45		9.68		27.7
8.0	16.60		12.90		28.7
10.0	20.75		16.12		28.7
12.0	24.90		19.35		28.7
14.0	29.05		22.58		28.7
16.0	33.20		25.80		27.7
18.0	37.35		29.03		27.2
20.5	42.53		33.06		25.7
21.9	45.44	2.6	39.52	1.8:1	24.2
22.6	46.86	5.9	45.97	4.7:1	22.5
23.5	48.76	9.0	52.42	3.5:1	21.2
23.9	49.59	12.6	58.87	9.0:1	20.2
24.3	50.41	16.2	65.32	9.0:1	19.2
24.5	50.83	20.2	71.77	19.0:1	18.5
24.8	51.45	23.7	78.23	12.3:1	17.7
25.2	52.28	27.3	84.68	9.0:1	17.5
25.5	52.90	31.0	91.13	12.3:1	17.2
25.7	53.32	34.8	97.58	19.0:1	17.0
25.8	53.53	36.7	100.80	20.0:1	16.7
25.8	53.53	38.7	104.03	∞	16.7

TABLE 30-B

Production History: Series J Waterflood, Test 2

Injection Rate = 80 cc/hr

Cum. Oil Production cc	% IOIP	Cum. Water Production cc	Water Injected % PV	Inst. WOR	ΔP PSIG
2.0	4.20		3.22		73.0
4.0	8.40		6.45		79.0
6.0	12.60		9.68		83.5
8.0	16.80		12.90		83.7
10.0	21.00		16.12		83.7
12.0	25.21		19.35		82.0
14.0	29.41		22.58		79.7
16.0	33.61		25.80		76.5
18.8	39.50		30.32		72.5
20.2	42.44	2.6	36.77	1.9:1	66.7
20.9	43.91	5.9	43.23	4.7:1	62.0
21.5	45.17	9.3	49.68	5.7:1	57.5
22.0	46.22	12.8	56.13	7.0:1	55.5
22.5	47.27	16.3	62.58	7.0:1	51.7
22.8	47.90	20.0	69.03	12.3:1	49.5
23.1	48.53	23.7	75.48	12.3:1	48.0
23.4	49.16	27.4	81.94	12.3:1	46.7
23.6	49.57	31.2	88.39	19.0:1	45.7
23.7	49.79	33.2	91.77	20.0:1	45.5
23.7	49.79	35.2	95.00	∞	45.2

TABLE 31-B

Production History: Series J Waterflood, Test 3

Injection Rate = 120 cc/hr

Cum. Oil Production cc	% IOIP	Cum. Water Production cc	Water Injected % PV	Inst. WOR	ΔP PSIG
2.0	4.20		3.22		95.0
4.0	8.40		6.45		111.5
6.0	12.60		9.68		121.5
8.0	16.80		12.90		124.0
10.0	21.00		16.12		123.0
12.0	25.21		19.35		120.0
14.0	29.41		22.58		114.0
16.0	33.61		25.80		110.0
18.5	38.87		29.83		103.5
19.9	41.81	2.6	36.29	1.9:1	96.0
20.5	43.07	6.0	42.74	5.7:1	91.0
21.0	44.12	9.5	49.19	7.0:1	83.5
21.5	45.17	13.0	55.65	7.0:1	80.0
21.9	46.00	16.6	62.10	9.0:1	75.0
22.2	46.64	20.3	68.55	12.3:1	73.5
22.5	47.27	24.0	75.00	12.3:1	70.0
22.7	47.69	27.8	81.45	19.0:1	68.0
22.8	47.90	29.8	84.84	20.0:1	67.0
22.8	47.90	33.7	91.13	∞	66.5

TABLE 32-B

Production History: Series J Waterflood, Test 4

Injection Rate = 200 cc/hr

Cum. Oil Production cc	% IOIP	Cum. Water Production cc	Water Injected % PV	Inst. WOR	ΔP PSIG
2.0	4.15		3.22		141.0
4.0	8.30		6.45		174.0
6.0	12.45		9.68		201.5
8.0	16.60		12.90		203.0
10.0	20.75		16.12		199.5
12.0	24.90		19.35		198.5
14.0	29.05		22.58		181.5
16.0	33.20		25.80		173.0
18.6	38.59		30.00		162.0
19.8	41.08	2.8	36.45	2.3:1	151.0
20.6	42.74	6.0	42.90	4.0:1	139.5
21.6	44.81	9.0	49.35	3.0:1	130.5
22.2	46.06	12.4	55.80	5.7:1	123.0
22.5	46.68	16.1	62.25	12.3:1	117.5
22.8	47.30	19.8	68.70	12.3:1	114.5
23.0	47.71	23.6	75.16	19.0:1	113.5
23.0	47.71	27.6	84.83	∞	113.0

TABLE 33-B

Production History: Series J Waterflood, Test 5

Injection Rate = 320 cc/hr

Cum. Oil Production cc	% IOIP	Cum. Water Production cc	Water Injected % PV	Inst. WOR	ΔP PSIG
2.0	4.15		3.22		240.0
4.0	8.30		6.45		290.0
6.0	12.45		9.68		---
8.0	16.60		12.90		---
10.0	20.75		16.12		---
12.0	24.90		19.35		---
14.0	29.05		22.58		---
16.7	34.64		26.93		280.0
17.7	36.72	3.0	33.38	3.0:1	260.0
18.7	38.79	6.0	39.83	3.0:1	249.0
19.3	40.04	9.4	46.29	5.7:1	239.0
19.9	41.28	12.8	52.74	5.7:1	229.5
20.2	41.90	16.5	59.19	12.3:1	220.0
20.5	42.53	20.2	65.64	12.3:1	212.5
20.7	42.94	24.0	72.09	19.0:1	205.0
20.9	43.36	27.8	78.54	19.0:1	200.5
21.0	43.56	31.7	85.00	39.0:1	193.0
21.0	43.56	38.7	96.29	∞	191.0

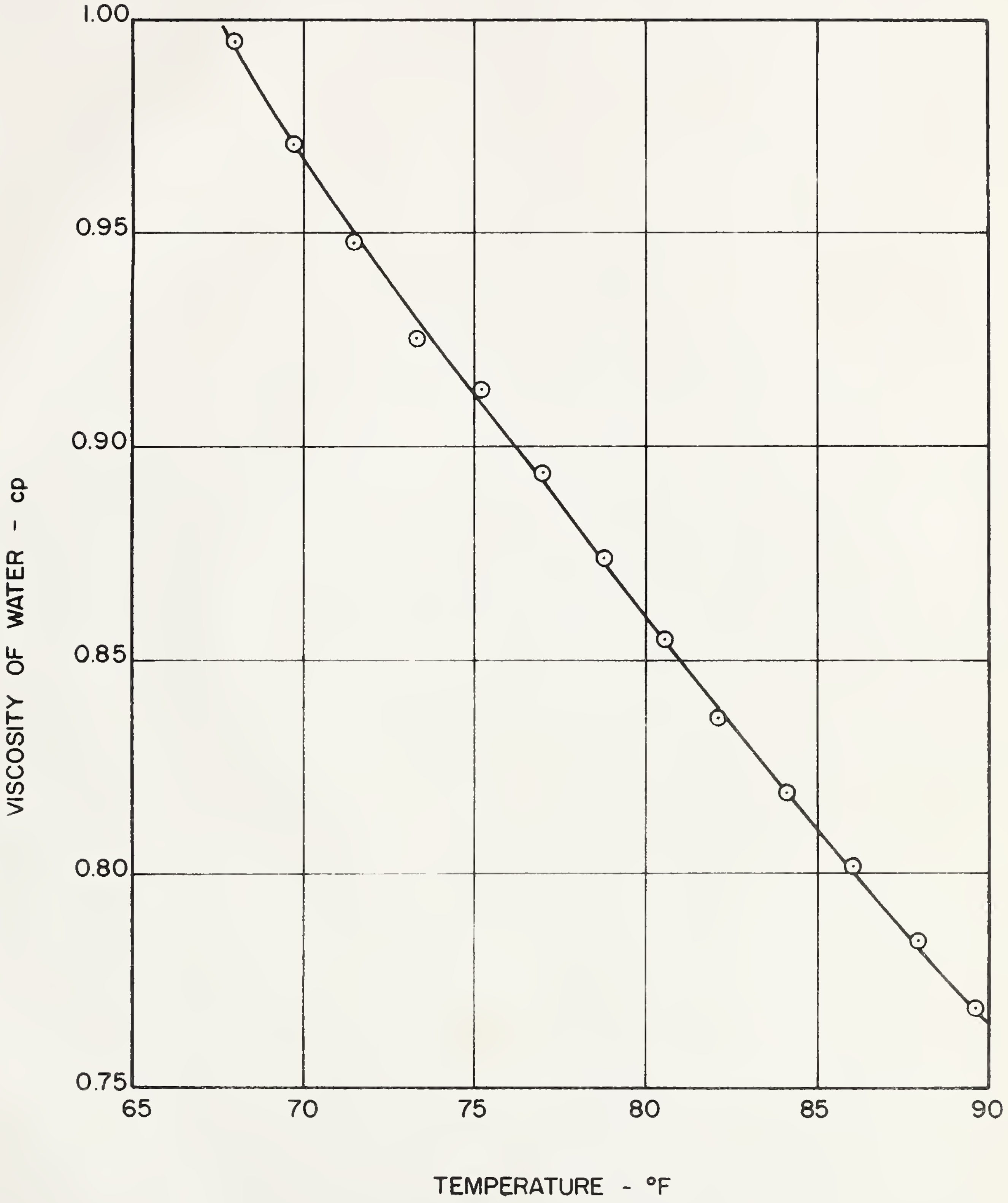

FIG. 8-B. RELATION BETWEEN VISCOSITY OF WATER AND TEMPERATURE. (From Reference 22.)

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